INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.
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Eric J. Holcomb
Governor

Bruno L. Pigott
Commissioner

NOTICE OF PERIOD FOR PUBLIC COMMENT

for Riverview Energy Corporation in Spencer County

New Source Construction and Part 70 Operating Permit No. T147-39554-00065

The Indiana Department of Environmental Management (IDEM) has received an application from Riverview Energy Corporation located at 4702 East 2000 North, Dale, Indiana 47532 for a new source construction and Part 70 Operating Permit. If approved by IDEM's Office of Air Quality (OAQ), this proposed permit would allow Riverview Energy Corporation to construct and operate a new stationary direct coal hydrogenation facility.

The applicant intends to construct and operate new equipment that will emit air pollutants. IDEM has reviewed this application, and has developed preliminary findings, consisting of a draft permit and several supporting documents, that would allow the applicant to construct and operate the facility.

On October 24, 2018, IDEM's Office of Air Quality (OAQ) had a notice published in The Journal-Democrat, in Rockport, Indiana stating that Riverview Energy Corporation had applied for a new source construction and Part 70 Operating Permit. The notice also stated that OAQ proposed to issue the operating permit to Riverview Energy Corporation and provided information on how the public could review the proposed Title V renewal permit and other documentation. The notice also stated that a Public Hearing would be held on November 29 at the Southridge High School in Huntington IN**. That public hearing will be rescheduled to another location and date, and a separate notice of the hearing will be provided.**

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

Lincoln Heritage Public Library
105 North Wallace Street
Dale, Indiana 46312

and

IDEM Southwest Regional Office
114 South 7th Street
Petersburg, IN 47567-0128

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

Written comments and supporting documentation may be sent to IDEM. Comments must be received by mail and postmarked no later than **December 10, 2018** or received by email no later than **December 10, 2018**. If you do not want to comment, but would like to be added to IDEM's mailing list to receive notice of future action related to this permit application, please contact IDEM. Please refer to permit number T147-39554-00065 in all correspondence.

Comments should be sent to:
Doug Logan, IDEM, Office of Air Quality
100 North Senate Avenue,
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
(800) 451-6027, and dial extension 317-234-5328
Or dial directly: (317) 234-5328
Fax: (317) 232-6749 attn: Doug Logan
E-mail: dlogan@idem.IN.gov

Any comments submitted in response to this notice should be limited to this permit renewal and related information in the supporting technical documents, as well as to the rules and laws pertaining to these items and their emission impacts. All written comments received during the public notice period and all comments made during the public hearing will be considered by IDEM when we make a decision to issue or deny the permit application. Comments that are most likely to affect final permit decisions are those based on the rules and laws governing this permitting process (326 IAC 2), air quality issues, and technical issues. IDEM does not have legal authority to regulate zoning, odor or noise. For such issues, please contact your local officials. For additional information about air permits and how you can participate, please see IDEM's **Guide for Citizen Participation** and **Permit Guide** on the Internet at: www.idem.in.gov.

What will happen after IDEM makes a decision?

Following the end of the public comment period, IDEM will issue a Notice of Decision stating whether the permit has been issued or denied. If the permit is issued, it may be different than the draft permit because of comments that were received during the public comment period. If comments are received during the public notice period, the final decision will include a document that summarizes the comments and IDEM's response to those comments. If you have submitted comments or have asked to be added to the mailing list, you will receive a Notice of the Decision. The notice will provide details on how you may appeal IDEM's decision, if you disagree with that decision. The final decision will also be available on the Internet at the address indicated above, at the local library indicated above, the IDEM public file room on the 12th floor of the Indiana Government Center North, 100 N. Senate Avenue, Indianapolis, Indiana 46204-2251, and the IDEM Southwest Regional Office, 114 S 7th St, P.O. Box 128, Petersburg Indiana 47567-0128. If you have any questions please contact Doug Logan of my staff at the above address.

Jenny Acker, Chief
Permits Branch
Office of Air Quality

JLA/dal

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Prevention of Significant Deterioration (PSD)/New Source Construction and Part 70 Operating Permit
OFFICE OF AIR QUALITY

Riverview Energy Corporation
4704 E 2000 N
Dale, Indiana 47523

(herein known as the Permittee) is hereby authorized to construct and 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.: T147-39554-00065 Master Agency Interest ID: 120104	
Issued by: Jenny Acker, Branch Chief Permits Branch Office of Air Quality	Issuance Date: Expiration Date:

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Attachment R: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR 63, Subpart DDDDD]

SECTION A SOURCE SUMMARY

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

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary direct coal hydrogenation (DCH) facility to convert coal to liquid fuels.

Source Address:	4704 E 2000 N, Dale, IN 47523
General Source Phone Number:	302-295-2761
SIC Code:	2911 (Petroleum Refining), 2999 (Products of Petroleum and Coal, Not Elsewhere Classified)
County Location:	Spencer
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)][326 IAC 2-7-5(14)]

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

(a) Coal handling operations, identified as Block 1000, consisting of:

(1) One (1) shelter-type railcar dump unloading facility, identified as EU-1000, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1000, exhausting to stack EU-1000, consisting of:

(A) Two (2) enclosed receiving pits, identified as Receiving Pit 1 and Receiving Pit 2, discharging to Receiving Bin 1 and Receiving Bin 2, respectively.
(B) Two (2) enclosed receiving bins, identified as Receiving Bin 1 and Receiving Bin 2, discharging to Drag Flight Feeder 1 and Drag Flight Feeder 2, respectively, with water spray dust suppression systems.
(C) Two (2) enclosed drag flight feeders, identified as Drag Flight Feeder 1 and Drag Flight Feeder 2, discharging to the Unloading Conveyor, with water spray dust suppression systems.

Under the NSPS, 40 CFR 60, Subpart Y, EU-1000 is an affected facility.

(2) One (1) enclosed rail unloading conveyor discharging to Transfer Station 1, identified as Unloading Conveyor, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

Under the NSPS, 40 CFR 60, Subpart Y, the Unloading Conveyor is an affected facility.

(3) One (1) enclosed transfer station discharging to Conveyor 1, Conveyor 2, or Conveyor 9, identified as Transfer Station 1 (EU-1001), approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

Under the NSPS, 40 CFR 60, Subpart Y, Transfer Station 1 (EU-1001) is an affected facility.

(4) One (1) enclosed feed conveyor discharging to Stacker 1 Boom Conveyor/Chute, identified as Conveyor 1, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 1 is an affected facility.

(5) One (1) enclosed stacker boom conveyor/chute discharging to Coal Stockpiles #1A & #1B, identified as Stacker 1 Boom Conveyor/Chute, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Stacker 1 Conveyor/Chute is an affected facility.

(6) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #1A and Stockpile #1B, with a maximum capacity of 93,000 tons, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Stockpiles #1A and #1B are affected facilities.

(7) One (1) enclosed feed conveyor discharging to Stacker 2 Boom Conveyor/Chute, identified as Conveyor 2, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 2 is an affected facility.

(8) One (1) enclosed stacker boom conveyor/chute discharging to Coal Stockpiles #2A & #2B, identified as Stacker 2 Boom Conveyor/Chute, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Stacker 2 Boom Conveyor/Chute is an affected facility.

(9) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #2A and Stockpile #2B, with a maximum capacity of 93,000 tons, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Stockpiles #2A and #2B are affected facilities.

(10) One (1) reclaimer for Stockpiles #1A & #1B, discharging to Reclaim Conveyor 6, identified as Reclaimer 1, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Reclaimer 1 is an affected facility.

(11) One (1) enclosed reclaimer conveyor, identified as Conveyor 6 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 6 is an affected facility.

(12) One (1) reclaimer for Stockpiles #2A & #2B, discharging to Reclaim Conveyor 7, identified as Reclaimer 2, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Reclaimer 2 is an affected facility.

(13) One (1) enclosed reclaimer conveyor, identified as Conveyor 7 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 7 is an affected facility.

(14) One (1) enclosed transfer station conveyor, identified as Conveyor 9 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 9 is an affected facility.

(15) One (1) enclosed reclaim transfer station discharging to Reclaim Conveyor 8, identified as Reclaim Transfer Station (EU-1006), approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Reclaim Transfer Station is an affected facility.

(16) One (1) enclosed conveyor, identified as Reclaim Conveyor 8 discharging to the Coal Mill and Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with particulate emissions controlled the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 8 is an affected facility.

(b) Coal drying loop, collectively identified as EU-1008, with emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008, consisting of the following:

(1) One (1) enclosed coal mill and pulverizer, identified as Coal Mill and Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer, with particulate emissions controlled the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Mill and Pulverizer is an affected facility.

(2) One (1) enclosed coal dryer, identified as Coal Dryer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer Baghouse, with particulate emissions controlled by the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer is an affected facility.

(3) One (1) natural gas and process fuel gas-fired heater, identified as Coal Dryer Heater EU-1007, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 55.8 MMBtu/hr (HHV), with emissions exhausting to Stack EU-1007.

Under the NSPS, 40 CFR 60, Subpart Ja, the Coal Dryer Heater (EU-1007) is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Heater (EU-1007) is part of an affected thermal dryer.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, the Coal Dryer Heater (EU-1007) is an affected source.

(4) One (1) process baghouse, identified as Coal Dryer Baghouse, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging fines to the Block 2000 Coal Hopper, exhausting particulate and filtered nitrogen to the condenser.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Baghouse is an affected facility.

(5) One (1) water-cooled condenser, identified as Drying Loop Condenser, approved in 2018 for construction, with a nominal capacity of 40 MMBtu/hr, with particulate emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008.

Under the NSPS, 40 CFR 60, Subpart Y, the Drying Loop Condenser is part of an affected thermal dryer.

(c) Additives handling operations, identified as Block 1500, consisting of:

- (1) Three (3) pneumatic (nitrogen) truck unloading systems discharging to storage silos, approved in 2018 for construction, as follows:
  - (A) Coarse Additive Unloading, with a maximum capacity of 20.00 tons per hour.
  - (B) Fine Additive Unloading, with a maximum capacity of 20.00 tons per hour.
  - (C) Sodium Sulfide (Na_2S) Unloading, with a maximum capacity of 10.00 tons per hour.
- (2) Three (3) nitrogen-blanketed storage silos, as follows:
  - (A) One (1) coarse additive silo, identified as T34, approved in 2018 for construction, controlled by baghouse EU-1501, exhausting to stack EU-1501.
  - (B) One (1) fine additive silo, identified as T33, approved in 2018 for construction, controlled by baghouse EU-1502, exhausting to stack EU-1502.
  - (C) One (1) Na_2S silo, identified as T35, approved in 2018 for construction, controlled by baghouse EU-1503, exhausting to stack EU-1503.
- (3) One (1) nitrogen-blanketed fine additive production system, identified as Fine Additive Production System, approved in 2018 for construction, with a maximum capacity of 3.28 tons per hour, controlled by baghouse EU-1504, exhausting to stack EU-1504, consisting of:
  - (A) One (1) coarse additive silo rotary feeder solid weigh scale.
  - (B) One (1) coarse additive screw conveyor discharging to the Fine Additive Production System.
  - (C) One (1) additive size reduction system, identified as Fine Additive Production System discharging to the T33 or the Block 2000 coarse additive transfer system.

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

- (1) One (1) enclosed hopper receiving coal from Block 1000 Coal Dryer Baghouse and discharging to the Feed Prep Screw Conveyor, identified as Coal Hopper, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year.

  Under the NSPS, 40 CFR 60, Subpart Y, the Coal Hopper is an affected facility.
- (2) One (1) enclosed screw conveyor, identified as Closed Screw Conveyor, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Feed Premix Drum, identified as Closed Screw Conveyor, with particulate emissions controlled by the Coal Handling System Filter, exhausting to stack EU-2005.

  Under the NSPS, 40 CFR 60, Subpart Y, the Closed Screw Conveyor is an affected facility.
- (3) One (1) nitrogen-blanketed coarse additive transfer system, identified as Coarse Additive Screw Conveyor, approved in 2018 for construction, with a maximum

capacity of 2.20 tons per hour, receiving material from the Block 1500 coarse additive silo and discharging to the Feed Premix Drum, with particulate emissions controlled by the Coarse Additive System Filter, exhausting to stack EU-2006.

(4) One (1) nitrogen-blanketed fine additive transfer system, identified as Fine Additive Handling System, approved in 2018 for construction, with a maximum capacity of 3.28 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Fine Additive System Filter, exhausting to stack EU-2007, consisting of:

(A) One (1) fine additive silo rotary feeder solid weigh scale.
(B) One (1) fine additive screw conveyor discharging to the Block 2000 feed premix drum.

(5) One (1) nitrogen-blanketed Na_2S slurry preparation system, identified as Na_2S Slurry Preparation, approved in 2018 for construction, with a maximum capacity of 0.077 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Na_2S Handling System Filter, exhausting to stack EU-2008, consisting of:

(A) One (1) Na_2S silo rotary feeder solid weigh scale.
(B) One (1) Na_2S screw conveyor discharging to the Na_2S mixing drum.
(C) One (1) nitrogen-blanketed mixing drum for Na_2S and Block 2000 vacuum tower VGO (vacuum gas oil) discharging to the feed premix drum.

Under the NSPS, 40 CFR 60, Subpart GGGa, the mixing drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the mixing drum is an affected source.

(6) One (1) feed premix drum, identified as Feed Premix Drum, approved in 2018 for construction, receiving coal, solid additives, and recycled vacuum gas oil (VGO) and discharging to the feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed premix drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed premix drum is an affected source.

(7) One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2018 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

Under the NSPS, 40 CFR 60, Subpart Ja, the feed heater EU-2001 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed heater EU-2001 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed heater EU-2001 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, feed heater EU-2001 is an affected source.

(8) One (1) natural gas and process fuel gas-fired indirect treat gas heater, identified as EU-2002, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 52.8 MMBtu/hr (HHV), receiving hydrogen from Block 7000 and discharging to the 1st stage reactors, exhausting to stack EU-2002.

Under the NSPS, 40 CFR 60, Subpart Ja, the treat gas heater EU-2002 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, treat gas heater EU-2002 is an affected source.

(9) One (1) first stage reactor - liquid phase hydrocracking system, identified as LPH, approved in 2018 for construction, discharging to the hot separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the first stage reactor - liquid phase hydrocracking system is an affected source.

(10) One (1) hot separator, identified as Hot Separator, approved in 2018 for construction, discharging vapor to the 2nd stage reactors and liquids to the vacuum column feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the hot separator is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the hot separator is an affected source.

(11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the vacuum distillation tower, exhausting to stack EU-2003.

Under the NSPS, 40 CFR 60, Subpart Ja, the vacuum column feed heater EU-2003 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum column feed heater EU-2003 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum column feed heater EU-2003 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, vacuum column feed heater EU-2003 is an affected source.

(12) One (1) vacuum distillation tower, identified as Vacuum Distillation Column, approved in 2018 for construction, discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 4000, phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum distillation tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the vacuum distillation tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum distillation tower is an affected source.

(13) One (1) second stage reactor - gas phase hydrotreating system, identified as GPH, approved in 2018 for construction, discharging to the cold separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the second stage reactor - gas phase hydrotreating system is an affected source.

(14) One (1) cold separator , identified as Cold Separator, approved in 2018 for construction, discharging non-phenolic sour water to Block 3000 and hydrocarbons to the fractionator heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the cold separator is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the cold separator is an affected source.

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

Under the NSPS, 40 CFR 60, Subpart Db, fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, the fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator heater is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator heater is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, fractionator heater EU-2004 is an affected source.

(16) One (1) fractionator tower, identified as Fractionator Tower, approved in 2018 for construction, discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix Drum, and non-phenolic sour water to Block 3000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the fractionator tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator tower is an affected source.

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

(A) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the HP Absorber and LP Absorber are affected sources.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the HP Absorber and LP Absorber is an affected source.

(e) Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

(A) One (1) heat exchanger, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) stripper column , identified as Stripper, approved in 2018 for construction, discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger and the reboiler and vapor to the overheads condenser, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(C) One (1) water-cooled condenser, identified as Overheads Condenser, approved in 2018 for construction, discharging condensate to the stripper condenser accumulator, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(D) One (1) accumulator drum, identified as Stripper Condenser Accumulator, approved in 2018 for construction, discharging condensate to stripper reflux and the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(E) One (1) steam-heated reboiler, identified as Stripper Reboiler, approved in 2018 for construction, discharging lean amine to the stripper reflux, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Amine Recovery Unit is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Amine Recovery Unit part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Amine Recovery Unit is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Amine Recovery Unit is an affected source.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Sour Water Stripping System is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Sour Water Stripping System is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Sour Water Stripping System is an affected source.

(3) Sulfur Recovery System, consisting of:

(A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the TGTU A Heat Exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605A Incinerator and A-605A Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit A is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit A is an affected source.

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr

(0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605B Incinerator and A-605B Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit B is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit B is an affected source.

(f) Offsites operations, identified as Block 4000, consisting of:

(1) Flares, as follows:

(A) One (1) natural gas and process fuel gas-fired flare identified as High Pressure (HP) Flare, approved in 2018 for construction, servicing overpressure and emergency reliefs from Block 2000 VEBA Combi Cracker operations, controlling emissions from Block 2000 depressurization system, with pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(B) One (1) natural gas and process fuel gas-fired flare, identified as Low Pressure (LP) Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 7000 Hydrogen Unit operations, controlling emissions Block 7000 start-up and shut-down vents, and a continuous sweep stream from the Block 2000 slop tank, with a sweep and pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(C) One (1) natural gas and process fuel gas-fired flare, identified as Sulfur Block Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 3000 Sulfur Recovery operations and sulfur loading, controlling emergency streams from Sulfur Recovery Units A and B, and a continuous sweep stream from the sour water storage tanks, with a sweep and pilot heat input capacity of 0.77 MMBtu/hr (LHV), exhausting to the atmosphere.

(D) One (1) natural gas and process fuel gas-fired flare, identified as Loading Flare, approved in 2018 for construction, servicing Block 4000 naphtha, diesel, and ammonia loading operations, with a pilot heat input capacity of 0.20 MMBtu/hr (LHV), exhausting to the atmosphere.

Under the NSPS, 40 CFR 60, Subpart Ja, the flares are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, the flares are affected facilities.

Under the NESHAP, 40 CFR 63, Subpart CC, the flares are affected sources.

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T1	IFR	Naphtha product	4,629,879 (17,524)	-
T2	IFR	Naphtha product	4,629,879 (17,524)	-
T3	FR	Diesel product	4,525,796 (17,130)	-
T4	FR	Diesel product	4,525,796 (17,130)	-
T5	FR	Diesel product	4,525,796 (17,130)	-
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)	-
T7	FR	Molten sulfur	342,367 (1,296)	-
T8	FR	Molten sulfur	342,367 (1,296)	-
T9	HPV	Ammonia product	36,720 (17,524)	-
T10	FR	Residue surge tank 1	926,980 (17,524)	-
T11	FR	Residue surge tank 2	926,980 (3,509)	-
T12	FR	Residue feed tank	926,980 (3,509)	-
T13	FR	VGO tank 1	926,980 (3,509)	-
T14	FR	VGO tank 2	926,980 (3,509)	-
T15	HPV	LPG storage	48,872 (185)	-
T16	FR	Slop tank	4,195,581 (15,880)	LP flare
T17	FR	Diesel fuel tank	23,775 (90)	-
T18	FR	Non-phenolic sour water storage tank 1	1,268,026 (4,799)	SB flare
T19	FR	Non-phenolic sour water storage tank 2	1,268,026 (4,799)	SB flare
T20	FR	Non-phenolic sour water storage tank 3	1,268,026 (4,799)	SB flare
T21	FR	Phenolic sour water storage tank	40,947 (155)	SB flare
T22	FR	Stripped non-phenolic sour water surge tank	1,268,026 (4,799)	-

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T23	FR	Stripped phenolic sour water surge tank	13,737 (52)	-
T24	FR	Amine surge/deinventory tank	63,943 (242)	-
T25	FR	Fresh amine tank	63,943 (242)	-
T26	FR	Amine containment tank (sump)	793 (3)	-

1. *FR - fixed roof, IFR - internal floating roof, HPV-horizontal pressure vessel*
2. *Tank vents to flares are part of sweep and pilot gas streams.*

Under the NSPS, 40 CFR 60, Subpart Kb, T1, T2, and T6 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, T1 - T6 and T10 - T15 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart QQQ, T16 is part of an affected facility.

Under the NSPS, 40 CFR 61, Subpart FF, T16 and T18 - T21 are part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, T1 - T6, T10 - T14, T16, and T18-T23 are part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart WW, T3 - T6 and T10 - T14 are affected sources.

(3) Loading operations, as follows:

(A) One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Product Loading Rack is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart BB, the Product Loading Rack is an affected source.

Under the NESHAP, 40 CFR 63, Subpart CC, the Product Loading Rack is an affected source.

(B) One (1) single-spot railcar loading rack for ammonia, identified as Ammonia Loading Rack, approved in 2018 for construction, with a bottlenecked capacity of 15,024,167 gallons per year, controlled by the Loading Flare.

(C) One (1) single-spot railcar loading rack for molten sulfur, identified as Sulfur Loading Rack, approved in 2018 for construction, with a bottlenecked capacity of 63,781 tons per year, controlled by the Sulfur Block Flare.

(g) Residue solidification operations, identified as Block 5000, as follows:

(1) Four (4) pastillators, identified as EU-5001A - EU5001D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5001.

(2) Four (4) pastillators, identified as EU-5002A - EU5002D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5002.

(3) Four (4) pastillators, identified as EU-5003A - EU5003D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5003.

(4) Four (4) pastillators, identified as EU-5004A - EU5004D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5004.

(5) Enclosed conveyors for residue pellets, with particulate emissions controlled by filters EU-5009, EU-5010, and EU-5011, as follows:

(A) One (1) enclosed conveyor, identified as Block 1 & 2 transfer conveyors, with a maximum capacity of 34.33 tons per hour, receiving pastillators from the eight (8) pastillators, identified as EU-5001A - EU5001D and EU-5002A - EU5002D.

(B) One (1) enclosed conveyor, identified as Block 3 & 4 transfer conveyors, with a maximum capacity of 34.33 tons per hour, receiving pastillators from the eight (8) pastillators, identified as EU-5003A - EU5003D and EU-5004A - EU5004D.

(C) One (1) enclosed loading conveyor, identified as Loading Conveyor, approved in 2018 for construction, with a maximum capacity of 51.49 tons per hour, receiving pastillators from Block 1 & 2 and Block 3 & 4 transfer conveyors, and discharging to the bulk container loading station, railcar residue silo, or swing residue silo.

(6) One (1) residue bulk container loading station, identified as EU-5009, approved in 2018 for construction, with a maximum capacity of 8.00 tons per hour, using filter EU-5009 for particulate control and exhausting to stack EU-5009.

(7) One (1) railcar residue storage silo, identified as EU-5010, approved in 2018 for construction, with a maximum capacity of 1,236 tons per day, using baghouse EU-5010 for particulate control and exhausting to stack EU-5010.

(8) Two (2) residue loading hoppers, identified as EU-5005 and EU-5006, approved in 2018 for construction, with a combined maximum capacity of 1,236 tons per day, receiving residue from the railcar residue storage silo, using baghouse EU-5010 for particulate control and exhausting to stack EU-5010.

(9) One (1) swing residue storage silo, identified as EU-5011, approved in 2018 for construction, with a maximum capacity of 1,236 tons per day, using baghouse EU-5011 for particulate control and exhausting to stack EU-5011.

(10) Two (2) residue loading hoppers, identified as EU-5007 and EU-5008, approved in 2018 for construction, with a combined maximum capacity of 1,236 tons per day, receiving residue from the swing residue storage silo, using baghouse EU-5011 for particulate control and exhausting to stack EU-5011.

(11) Residue loadout operations using spouts and choke flow-practices, as follows:

(A) Two (2) railcar loadspots, approved in 2018 for construction.

(B) Two (2) swing loadspots, approved in 2018 for construction, accommodating either trucks or railcars.

(h) Utilities operations, identified as Block 6000, consisting of:

(1) One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 68.50 MMBtu/hr (HHV), exhausting to stack EU-6000.

Under the NSPS, 40 CFR 60, Subpart Dc, boiler EU-6000 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, boiler EU-6000 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, boiler EU-6000 is an affected source.

(2) One (1) three-cell crossflow mechanical draft cooling tower, identified as EU-6001, approved in 2018 for construction, with a maximum capacity of 32,000 gallons per hour, equipped with mist eliminators and exhausting to stacks EU-6001, EU-6002, and EU-6003.

(3) One (1) diesel engine-driven emergency generator, identified as EU-6006, approved in 2018 for construction, with a maximum heat input capacity of 19.60 MMBtu/hr (2,800 hp) (average heating value), exhausting to stack EU-6006.

Under the NSPS, 40 CFR 60, Subpart IIII, emergency generator EU-6006 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart ZZZZ, emergency generator EU-6006 is an affected source.

(4) One (1) diesel engine-driven emergency fire pump, identified as EU-6008, approved in 2018 for construction, with a maximum heat input capacity of 5.25 MMBtu/hr (750 hp) (average heating value), exhausting to stack EU-6008.

Under the NSPS, 40 CFR 60, Subpart IIII, emergency fire pump EU-6008 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart ZZZZ, emergency fire pump EU-6008 is an affected source.

(i) Water supply and treatment operations, identified as Block 6500, consisting of:

(1) One (1) pneumatic lime truck unloading system, identified as Lime Unloading, approved in 2018 for construction, with a maximum capacity of 20.00 tons per hour, discharging to silo EU-6501.

(2) One (1) lime storage silo, identified as EU-6501, approved in 2018 for construction, with a maximum capacity of 20.00 tons per hour, with particulate emissions controlled by dust collector EU-6501 and exhausting to stack EU-6501.

(j) Hydrogen unit operations, identified as Block 7000, as follows:

(1) Hydrogen Plant 1, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7003, identified as Feed Water Treatment System 1, approved in 2018 for construction, exhausting to stack EU-7003.

(B) One (1) feed preparation train, identified as Feed Prep 1, approved in 2018 for construction, consisting of:

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7001, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7001, is an affected facility.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 1, approved in 2018 for construction, discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 1, approved in 2018 for construction, discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 1 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 1 is an affected source.

(2) Hydrogen Plant 2, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7004, identified as Feed Water Treatment System 2, approved in 2018 for construction, exhausting to stack EU-7004.

(B) One (1) feed preparation train, identified as Feed Prep 2, approved in 2018 for construction, consisting of:

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7002, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7002, is an affected facility.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 2, approved in 2018 for construction, discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 2, approved in 2018 for construction, discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 2 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 2 is an affected source.

(k) Wastewater treatment operations, identified as Block 8000, as follows:

(1) One (1) wastewater junction box with associated process drains, identified as Oily Water Sump, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8002.

(2) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Water Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and water to MH1.

(3) One (1) wastewater junction box with, identified as MH1, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8003.

(4) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Amine Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and amine solution to the Rich Amine Return Header.

(5) One (1) biological wastewater treatment system, approved in 2018 for construction, with emissions exhausting to vent EU-8001.

Under the NSPS, 40 CFR 60, Subpart QQQ, the process drains, junction boxes, Oily Water Separator, Oily Amine Separator, associated sewer lines, and any secondary oil-water separator in the biological wastewater treatment system are an affected aggregate facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Oily Water Separator, Oily Amine Separator, and any secondary oil-water separator in the biological wastewater treatment system are affected sources.

Under the NESHAP, 40 CFR 63, Subpart CC, the wastewater streams and treatment operations associated with petroleum refining process units are part of a new affected source..

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)][326 IAC 2-7-4(c)][326 IAC 2-7-5(14)]

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

(a) The following VOC and HAP storage containers:

(1) Storage tanks with capacity less than or equal to one thousand (1,000) gallons and annual throughputs equal to or less than twelve thousand (12,000) gallons.

(2) Vessels storing the following:

(A) Hydraulic oils.
(B) Lubricating oils.

(b) Production related activities, including the following:

(1) Cleaners and solvents characterized as having a vapor pressure equal to or less than:

(A) two (2.0) kilo Pascals (fifteen (15) millimeters of mercury or three-tenths (0.3) pound per square inch) measured at thirty-eight (38) degrees Centigrade (one hundred (100) degrees Fahrenheit); or
(B) seven-tenths (0.7) kilo Pascal (five (5) millimeters of mercury or one-tenth (0.1) pound per square inch) measured at twenty (20) degrees Centigrade (sixty-eight (68) degrees Fahrenheit); the use of which, for all cleaners and solvents combined, does not exceed one hundred forty-five (145) gallons per twelve (12) months.

(2) Closed loop heating and cooling systems.

(c) Repair activities, including the following:

    (1) Replacement or repair of electrostatic precipitators, bags in baghouses, and filters in other air filtration equipment.
    (2) Heat exchanger cleaning and repair.
    (3) Process vessel degassing and cleaning to prepare for internal repairs.

(d) Paved roads and parking lots with public access.

(e) Conveyors as follows:

    (1) Underground conveyors.

(f) Routine maintenance and repair of buildings, structures, or vehicles at the source where air emissions from those activities would not be associated with any production process, including the following:

    (1) Purging of gas lines.
    (2) Purging of vessels.

(g) Flue gas conditioning systems and associated chemicals, such as the following:

    (1) Ammonia.

(h) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including the following:

    (1) Tanks.
    (2) Fluid handling equipment.

(i) Blowdown for the following:

    (1) Boiler.
    (2) Cooling tower.

(j) Activities associated with emergencies as follows:

    (1) On-site fire training approved by IDEM.

(k) Purge double block and bleed valves.

(l) An emission unit or activity whose potential uncontrolled emissions meet the exemption levels specified in 326 IAC 2-1.1-3(e)(1) or the exemption levels specified in the following, whichever is lower:

- For lead or lead compounds measured as elemental lead, the exemption level is six-tenths (0.6) ton per year or three and twenty-nine hundredths (3.29) pounds per day.
- For carbon monoxide (CO), the exemption limit is twenty-five (25) pounds per day.
- For sulfur dioxide, the exemption level is five (5) pounds per hour or twenty-five (25) pounds per day.
- For VOC, the exemption limit is three (3) pounds per hour or fifteen (15) pounds per day.
- For nitrogen oxides (NOx), the exemption limit is five (5) pounds per hour or twenty-five (25) pounds per day.

- For PM10 or direct PM2.5, the exemption level is either five (5) pounds per hour or twenty-five (25) pounds per day.

As follows:

(1) Fugitive leaks of VOC and HAPs from equipment in VOC service, subject to NSPS or NESHAP, but individually less than the exemption levels listed above.

(2) One (1) emergency generator fuel tank, identified as EU-6005, approved in 2018 for construction, with a nominal capacity of 2,000 gallons and an expected annual throughput of 69,450 gallons, using no controls and exhausting to stack EU-6005.

(3) One (1) emergency fire pump fuel tank, identified as EU-6007, approved in 2018 for construction, with a nominal capacity of 500 gallons and an expected annual throughput of 19,950 gallons, using no controls and exhausting to stack EU-6007.

A.4 Part 70 Permit Applicability [326 IAC 2-7-2]

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

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

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

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 Revocation of Permits [326 IAC 2-2-8]

Pursuant to 326 IAC 2-2-8(a)(1), this permit to construct shall expire if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is discontinued for a period of eighteen (18) months or more.

B.3 Affidavit of Construction [326 IAC 2-5.1-3(h)] [326 IAC 2-5.1-4]

This document shall also become the approval to operate pursuant to 326 IAC 2-5.1-4 when prior to the start of operation, the following requirements are met:

(a) The attached Affidavit of Construction shall be submitted to the Office of Air Quality (OAQ), verifying that the emission units were constructed as proposed in the application or the permit. The emission units covered in this permit may begin operating on the date the Affidavit of Construction is postmarked or hand delivered to IDEM if constructed as proposed.

(b) If actual construction of the emission units differs from the construction proposed in the application, the source may not begin operation until the permit has been revised pursuant to 326 IAC 2 and an Operation Permit Validation Letter is issued.

(c) The Permittee shall attach the Operation Permit Validation Letter received from the Office of Air Quality (OAQ) to this permit.

B.4 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, T147-39554-00065, 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.5 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.6 Enforceability [326 IAC 2-7-7] [IC 13-17-12]

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

B.7 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.8 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.9 Duty to Provide Information [326 IAC 2-7-5(6)(E)]

(a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. Upon request, the Permittee shall also furnish to IDEM, OAQ copies of records required to be kept by this permit.

(b) For information furnished by the Permittee to IDEM, OAQ, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1. When furnishing copies of requested records directly to U. S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.

B.10 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]

(a) A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:

(1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(35), and

(2) the certification states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) The Permittee may use the attached Certification Form, or its equivalent with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.

(c) A "responsible official" is defined at 326 IAC 2-7-1(35).

B.11 Annual Compliance Certification [326 IAC 2-7-6(5)]

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

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

and

United States Environmental Protection Agency, Region V
Air and Radiation Division, Air Enforcement Branch - Indiana (AE-17J)

77 West Jackson Boulevard
Chicago, Illinois 60604-3590

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

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

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

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

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

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

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

B.12 Preventive Maintenance Plan [326 IAC 2-7-5(12)][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) no later than ninety (90) days after issuance of this permit or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee's control, the PMPs cannot be prepared and maintained within the above time frame, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

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

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

The Permittee shall implement the PMPs.

(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. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(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.13 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 or Southwest Regional Office within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or
Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)
Facsimile Number: 317-233-6865
Southwest Regional Office phone: (812) 380-2305; fax: (812) 380-2304**.**

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

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

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

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

(A) A description of the emergency;

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

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

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

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

(e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4(c)(8) be revised in response to an emergency.

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

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

B.14 Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]

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

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

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

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

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

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

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

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

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

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

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

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

B.15 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 T147-39554-00065 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.16 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.17 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

(1) That this permit contains a material mistake.

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

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

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

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

B.18 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(42). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Request for renewal shall be submitted to:

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

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

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

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

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

B.19 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
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

B.20 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]

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

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

B.21 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]

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

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

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

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

(4) The Permittee notifies the:

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

and

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

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

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-7-20(b)(1) and (c)(1). The Permittee shall make such records available, upon reasonable request, for public review.

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

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(37)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

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

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

(3) Any change in emissions; and

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

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

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

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

B.22 Source Modification Requirement [326 IAC 2-7-10.5]

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

B.23 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.24 Transfer of Ownership or Operational Control [326 IAC 2-7-11]

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

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

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

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

B.25 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.26 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 5-1-1 (Applicability) and 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

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

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

C.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 except as provided in 326 IAC 4-2 or in this permit. The Permittee shall not operate a refuse incinerator or refuse burning equipment except as provided in 326 IAC 9-1-2 or in this permit.

C.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 Stack Height [326 IAC 1-7]

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

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

(a) Notification requirements apply to each owner or operator. If the combined amount of regulated asbestos containing material (RACM) to be stripped, removed or disturbed is at least 260 linear feet on pipes or 160 square feet on other facility components, or at least thirty-five (35) cubic feet on all facility components, then the notification requirements of

326 IAC 14-10-3 are mandatory. All demolition projects require notification whether or not asbestos is present.

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

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

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

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

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

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

All required notifications shall be submitted to:

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

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

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

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

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

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

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

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

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

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

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

Compliance Requirements [326 IAC 2-1.1-11]

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

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

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

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

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

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

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

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

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

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

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

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

C.11 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5] [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, as required in Sections D or E of this permit.

(b) All continuous emission monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) 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.

(d) Whenever a continuous emission monitoring system is down for more than twenty-four (24) hours, the Permittee shall follow good air pollution control practices.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5 or any applicable requirements.

C.12 Maintenance of Emission Monitoring Equipment [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

(a) In the event that a breakdown of the emission monitoring equipment occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem. To the extent practicable, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less frequent than required in Section D of this permit until such time as the monitoring equipment is back in operation. In the case of continuous monitoring, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less often than once an hour until such time as the continuous monitor is back in operation.

(b) The Permittee shall install, calibrate, quality assure, maintain, and operate all necessary monitors and related equipment.

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

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

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

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

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

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

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

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

no later than ninety (90) days after the date of issuance of this permit.

The ERP does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) 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(11)] [40 CFR 68]

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

C.16 Response to Excursions or Exceedances [40 CFR 64][326 IAC 3-8][326 IAC 2-7-5] [326 IAC 2-7-6]

(I) Upon detecting an excursion where a response step is required by the D Section, or an exceedance of a limitation, not subject to CAM, in this permit:

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

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

(1) initial inspection and evaluation;

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

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

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

(1) monitoring results;

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

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

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

(e) The Permittee shall record the reasonable response steps taken.

(II)

(a) CAM *Response to excursions or exceedances.*
(1) Upon detecting an excursion or exceedance, subject to CAM, the Permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial

inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(2) Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

(b) If the Permittee identifies a failure to achieve compliance with an emission limitation, subject to CAM, or standard, subject to CAM, for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the IDEM, OAQ and, if necessary, submit a proposed significant permit modification to this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

(c) Based on the results of a determination made under paragraph (II)(a)(2) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a Quality Improvement Plan (QIP). The Permittee shall develop and implement a QIP if notified to in writing by the EPA or IDEM, OAQ.

(d) Elements of a QIP:
The Permittee shall maintain a written QIP, if required, and have it available for inspection. The plan shall conform to 40 CFR 64.8 b (2).

(e) If a QIP is required, the Permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the IDEM, OAQ if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(f) Following implementation of a QIP, upon any subsequent determination pursuant to paragraph (II)(a)(2) of this condition the EPA or the IDEM, OAQ may require that the Permittee make reasonable changes to the QIP if the QIP is found to have:

(1) Failed to address the cause of the control device performance problems; or

(2) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(g) Implementation of a QIP shall not excuse the Permittee from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(h) *CAM recordkeeping requirements.*

(1) The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to paragraph (II)(c) of this condition and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this condition (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions). Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

(2) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements

C.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 submit a description of its response actions to IDEM, OAQ no later than seventy-five (75) days after the date of the test.

(b) A retest to demonstrate compliance shall be performed no later than one hundred eighty (180) days after the date of the test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred eighty (180) days is not practicable, IDEM, OAQ may extend the retesting deadline.

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

The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

C.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]

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(33) (“Regulated pollutant, which is used only for purposes of Section 19 of this rule”) from the source, for purpose of fee assessment.

The statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue

MC 61-50 IGCN 1003
Indianapolis, Indiana 46204-2251

The emission statement does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

C.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. Support information includes the following, where applicable:

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

Records of required monitoring information include the following, where applicable:

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

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

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

(c) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A), 326 IAC 2-2-8 (b)(6)(B), 326 IAC 2-3-2 (l)(6)(A), and/or 326 IAC 2-3-2 (l)(6)(B)) that a “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a “major modification” (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Before beginning actual construction of the “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, document and maintain the following records:

(A) A description of the project.

(B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project.

(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:

(i) Baseline actual emissions;

(ii) Projected actual emissions;

(iii) Amount of emissions excluded under section 326 IAC 2-2-1(pp)(2)(A)(iii) and/or 326 IAC 2-3-1 (kk)(2)(A)(iii); and

(iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.

(d) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A) and/or 326 IAC 2-3-2 (l)(6)(A)) that a “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a “major modification” (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

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

(2) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) years following resumption of regular operations after the change if the project increases the design capacity of or the potential to emit that regulated NSR pollutant at the emissions unit.

C.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] [40 CFR 64][326 IAC 3-8]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B -Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

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

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

(1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

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

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

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

(b) The address for report submittal is:

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

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

(d) The first report shall cover the period commencing on the date of issuance of this permit or the date of initial start-up, whichever is later, 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.

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

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

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

(f) The report for project at an existing emissions unit shall be submitted no later than sixty (60) days after the end of the year and contain the following:

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

(2) The annual emissions calculated in accordance with (d)(1) and (2) in Section C - General Record Keeping Requirements.

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

(4) Any other information that the Permittee wishes to include in this report such as an explanation as to why the emissions differ from the preconstruction projection.

Reports required in this part shall be submitted to:

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

(g) 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 applicable standards for recycling and emissions reduction.

SECTION D.0 EMISSIONS UNIT OPERATION CONDITIONS - Construction

Emissions Unit Description:

Entire Source

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

General Construction Conditions

D.0.1 Permit No Defense

This permit 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 there under, as well as other applicable local, state, and federal requirements.

Effective Date of the Permit

D.0.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.0.3 Modifications to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS - Coal Handling

Emissions Unit Description:

(a) Coal handling operations, identified as Block 1000, consisting of:

(1) One (1) shelter-type railcar dump unloading facility, identified as EU-1000, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1000, exhausting to stack EU-1000, consisting of:

(A) Two (2) enclosed receiving pits, identified as Receiving Pit 1 and Receiving Pit 2, discharging to Receiving Bin 1 and Receiving Bin 2, respectively.
(B) Two (2) enclosed receiving bins, identified as Receiving Bin 1 and Receiving Bin 2, discharging to Drag Flight Feeder 1 and Drag Flight Feeder 2, respectively, with water spray dust suppression systems.
(C) Two (2) enclosed drag flight feeders, identified as Drag Flight Feeder 1 and Drag Flight Feeder 2, discharging to the Unloading Conveyor, with water spray dust suppression systems.

Under the NSPS, 40 CFR 60, Subpart Y, EU-1000 is an affected facility.

(2) One (1) enclosed rail unloading conveyor discharging to Transfer Station 1, identified as Unloading Conveyor, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

Under the NSPS, 40 CFR 60, Subpart Y, the Unloading Conveyor is an affected facility.

(3) One (1) enclosed transfer station discharging to Conveyor 1, Conveyor 2, or Conveyor 9, identified as Transfer Station 1 (EU-1001), approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

Under the NSPS, 40 CFR 60, Subpart Y, Transfer Station 1 (EU-1001) is an affected facility.

(4) One (1) enclosed feed conveyor discharging to Stacker 1 Boom Conveyor/Chute, identified as Conveyor 1, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 1 is an affected facility.

(5) One (1) enclosed stacker boom conveyor/chute discharging to Coal Stockpiles #1A & #1B, identified as Stacker 1 Boom Conveyor/Chute, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Stacker 1 Conveyor/Chute is an affected facility.

(6) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #1A and Stockpile #1B, with a maximum capacity of 93,000 tons, controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Stockpiles #1A and #1B are affected facilities.

(7) One (1) enclosed feed conveyor discharging to Stacker 2 Boom Conveyor/Chute, identified as Conveyor 2, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 2 is an affected facility.

(8) One (1) enclosed stacker boom conveyor/chute discharging to Coal Stockpiles #2A & #2B, identified as Stacker 2 Boom Conveyor/Chute, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Stacker 2 Boom Conveyor/Chute is an affected facility.

(9) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #2A and Stockpile #2B, with a maximum capacity of 93,000 tons, controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Stockpiles #2A and #2B are affected facilities.

(10) One (1) reclaimer for Stockpiles #1A & #1B, discharging to Reclaim Conveyor 6, identified as Reclaimer 1, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Reclaimer 1 is an affected facility.

(11) One (1) enclosed reclaimer conveyor, identified as Conveyor 6 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 6 is an affected facility.

(12) One (1) reclaimer for Stockpiles #2A & #2B, discharging to Reclaim Conveyor 7, identified as Reclaimer 2, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Reclaimer 2 is an affected facility.

(13) One (1) enclosed reclaimer conveyor, identified as Conveyor 7 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year,

with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 7 is an affected facility.

(14) One (1) enclosed transfer station conveyor, identified as Conveyor 9 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 9 is an affected facility.

(15) One (1) enclosed reclaim transfer station discharging to Reclaim Conveyor 8, identified as Reclaim Transfer Station (EU-1006), approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Reclaim Transfer Station is an affected facility.

(16) One (1) enclosed conveyor, identified as Reclaim Conveyor 8 discharging to the Coal Mill and Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with emissions controlled the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 8 is an affected facility.

(b) Coal drying loop, collectively identified as EU-1008, with emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU -1008, consisting of the following:

(1) One (1) enclosed coal mill and pulverizer, identified as Coal Mill and Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer, with particulate emissions controlled the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Mill and Pulverizer is an affected facility.

(2) One (1) enclosed coal dryer, identified as Coal Dryer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer Baghouse, with particulate emissions controlled by the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer is an affected facility.

(3) One (1) natural gas and process fuel gas-fired heater, identified as Coal Dryer Heater EU-1007, approved in 2018 for construction, with a maximum heat input capacity of 55.8 MMBtu/hr (HHV), with emissions exhausting to Stack EU-1007.

Under the NSPS, 40 CFR 60, Subpart Ja, the Coal Dryer Heater (EU-1007) is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Heater (EU-1007) is part of an affected thermal dryer.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, the Coal Dryer Heater (EU-1007) is an affected source.

(4) One (1) process baghouse, identified as Coal Dryer Baghouse, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging fines to the Block 2000 Coal Hopper, exhausting particulate and filtered nitrogen to the condenser.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Baghouse is an affected facility.

(5) One (1) water-cooled condenser, identified as Drying Loop Condenser, approved in 2018 for construction, with a nominal capacity of 40 MMBtu/hr, controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008.

Under the NSPS, 40 CFR 60, Subpart Y, the Drying Loop Condenser is part of an affected thermal dryer.

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(1) One (1) enclosed hopper receiving coal from Block 1000 Coal Dryer Baghouse and discharging to the Feed Prep Screw Conveyor, identified as Coal Hopper, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Hopper is an affected facility.

(2) One (1) enclosed screw conveyor, identified as Closed Screw Conveyor, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Feed Premix Drum, identified as Closed Screw Conveyor, with particulate emissions controlled by the Coal Handling System Filter, exhausting to stack EU-2005.

Under the NSPS, 40 CFR 60, Subpart Y, the Closed Screw Conveyor is an affected facility.

(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 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]

(a) Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the coal handling operations shall be as follows:

Emission Unit Description (ID)	**Control Device (Stack ID)**	**Emission Limitations**		
		Pollutant	**gr/dscf**	**lb/hr**
Railcar unloading, including: Receiving Pits 1 & 2 Receiving Bins 1 & 2 Drag Flight Feeders 1& 2 (EU-1000)	Baghouse EU-1000 (stack EU-1000) Water spray dust suppression (bins & feeders only)	PM	0.0022	0.12
		PM_{10}	0.0022	0.12
		$PM_{2.5}$	0.0022	0.12

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	**gr/dscf**	**lb/hr**
Transfer station, including: Unloading Conveyor (EU-1001)	Baghouse EU-1001 (stack EU-1001)	PM	0.002	0.16
		PM_{10}	0.002	0.16
		$PM_{2.5}$	0.002	0.16
Coal storage enclosure 1, including Conveyor 1 Stacker 1 Boom/Chute Stockpiles #1A & #1B Reclaimer 1 Coal storage enclosure 2, including: Conveyor 2 Stacker 2 Boom/Chute Stockpiles #2A & #2B Reclaimer 2 Reclaim transfer station, including: Conveyor 6 Conveyor 7 Conveyor 9	Baghouse EU-1006 (stack EU-1006)	PM	0.002	0.11
		PM_{10}	0.002	0.11
		$PM_{2.5}$	0.002	0.11
Coal drying loop purge, including: Conveyor 8 Coal mill & pulverizer Coal Dryer	Loop Purge Baghouse (stack EU-1008)	PM	0.002	0.26
		PM_{10}	0.002	0.26
		$PM_{2.5}$	0.002	0.26
Enclosed screw conveyor to Block 2000 feed premix drum	Coal Handling System Filter (stack EU-2005)	PM	0.002	0.003
		PM_{10}	0.002	0.003
		$PM_{2.5}$	0.002	0.003

PM_{10} and $PM_{2.5}$ include both filterable and condensable PM.

(b) There shall be no (0%) visible emissions from the entrance and exit doors of the unloading enclosure at any time.

D.1.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.1.3 Particulate Control

(a) In order to assure compliance with Condition D.1.1, the following control devices for particulate control shall be in operation and control particulate emissions from the associated emission units at all times those emission units are in operation:

Emission Unit Description	Unit ID	Control Device
Railcar unloading	EU-1000	Baghouse EU-1000 Water spray dust suppression (hoppers & feeders only)
Transfer station	EU-1001	Baghouse EU-1001
Coal storage enclosure 1 Coal storage enclosure 2 Reclaim transfer station	EU-1006	Baghouse EU-1006
Coal drying loop	EU-1008	Baghouse EU-1008
Enclosed screw conveyor to Block 2000 feed premix drum	EU-2005	Coal Handling System Filter EU-2005

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

D.1.4 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.1.1(a), not later than 180 days after the startup of the emission units listed in the table below, the Permittee shall perform opacity, PM, PM_{10}, and $PM_{2.5}$ testing of the emission units listed in the table below utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration.

Emission Unit	Baghouse ID
Railcar unloading	EU-1000
Transfer station	EU-1001
Coal storage enclosure 1 Coal storage enclosure 2 Reclaim transfer station	EU-1006
Coal drying loop purge	EU-1008
Enclosed screw conveyor to Block 2000 feed premix drum	EU-2005

(b) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee’s obligation with regard to the performance testing required by this condition. PM_{10} and $PM_{2.5}$ includes filterable and condensable PM.

D.1.5 Coal Unloading Enclosure Monitoring

In order to assure compliance with Condition D.1.1, the Permittee shall:

(a) Construct, operate, and maintain a total enclosure for the coal unloading operation that is free of cracks, gaps, corrosion, or other deterioration.

(b) Ventilate the unloading enclosure continuously ensure negative pressure values of at least thirteen-thousandths (0.013) millimeters of mercury (seven-thousandths (0.007) inches of water) across each door.

or

Maintain an inward flow of air through the entrance and exit doors at a velocity greater than or equal to 200 feet per minute (1.016 m/sec).

D.1.6 Coal Storage Enclosure Monitoring

In order to assure compliance with Condition D.1.1, the Permittee shall:

(a) Construct, operate, and maintain a total enclosure for each coal storage enclosure (consisting of a conveyor from the transfer station, stacker boom/chute, two (2) stockpiles, and reclaimer), each reclaim conveyor, and the reclaim transfer station that is free of cracks, gaps, corrosion, or other deterioration.

(b) Ventilate each storage enclosure continuously to ensure negative pressure values of at least thirteen-thousandths (0.013) millimeters of mercury (seven-thousandths (0.007) inches of water) across each door.

or

Maintain an inward flow of air through each opening at a velocity greater than or equal to 200 feet per minute (1.016 m/sec).

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

D.1.7 Parametric Monitoring

The Permittee shall record the pressure drop across the baghouses listed in the table below at least once per day when the associated emissions unit is in operation. When, for any one reading, the pressure drop across a baghouse is outside the normal range, the Permittee shall take a reasonable response. The normal range for this unit is a pressure drop between 3.0 and 6.0 inches of water unless a different upper-bound or lower-bound value for this range is determined during the latest stack test. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

Baghouse ID
EU-1000
EU-1001
EU-1006
EU-1008
EU-2005

The instruments used for determining the pressure shall comply with Section C – Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months.

D.1.8 Enclosure Monitoring

(a) The Permittee shall record the negative pressure or velocity at each unloading enclosure door at least once per day when the associated emissions unit is in operation. When, for any one reading, a measured value is outside the following specifications, the Permittee shall take a reasonable response.

Parameter	Range
Negative Pressure	Equal to or Greater than 0.013 millimeters or seven-thousandths (0.007) inches of water
Inward Velocity	200 feet per minute (1.016 m/sec)

(b) The instruments used for determining the pressure shall comply with Section C – Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months.

D.1.9 Enclosure Inspection

(a) The Permittee shall inspect the unloading enclosure and structure at least once per month.

(b) The Permittee shall inspect each storage enclosure and structure at least once per month.

D.1.10 Broken or Failed Bag Detection

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

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

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

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

D.1.11 Record Keeping Requirement

(a) To document the compliance status with Condition D.1.7, the Permittee shall maintain daily records of pressure drop across the baghouse(s). The Permittee shall include in its daily record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading (e.g. the process did not operate that day).

(b) To document the compliance status with Condition D.1.8(a), the Permittee shall maintain daily records of negative pressure across each unloading enclosure door or air velocity. The Permittee shall include in its daily record when a measurement is not taken and the reason for the lack of a measurement (e.g. the process did not operate that day).

(c) To document the compliance status with Condition D.1.8(b), the Permittee shall maintain daily records of negative pressure across each storage enclosure or air velocity. The Permittee shall include in its daily record when a measurement is not taken and the reason for the lack of a measurement (e.g. the process did not operate that day).

(d) To document the compliance status with Condition D.1.9(a), the Permittee shall maintain records of the dates and results of the unloading enclosure inspections.

(e) To document the compliance status with Condition D.1.9(b), the Permittee shall maintain records of the dates and results of the storage enclosure inspections.

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

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS - Additives

Emissions Unit Description:

(c) Additives handling operations, identified as Block 1500, consisting of:

(1) Three (3) pneumatic (nitrogen) truck unloading systems discharging to storage silos, approved in 2018 for construction, as follows:

(A) Coarse Additive Unloading, with a maximum capacity of 20.00 tons per hour.
(B) Fine Additive Unloading, with a maximum capacity of 20.00 tons per hour.
(C) Sodium Sulfide (Na_2S) Unloading, with a maximum capacity of 10.00 tons per hour.

(2) Three (3) nitrogen-blanketed storage silos, as follows:

(A) One (1) coarse additive silo, identified as T34, approved in 2018 for construction, controlled by baghouse EU-1501, exhausting to stack EU-1501.
(B) One (1) fine additive silo, identified as T33, approved in 2018 for construction, controlled by baghouse EU-1502, exhausting to stack EU-1502.
(C) One (1) Na_2S silo, identified as T35, approved in 2018 for construction, controlled by baghouse EU-1503, exhausting to stack EU-1503.

(3) One (1) nitrogen-blanketed fine additive production system, identified as Fine Additive Production System, approved in 2018 for construction, with a maximum capacity of 3.28 tons per hour, controlled by baghouse EU-1504, exhausting to stack EU-1504, consisting of:

(A) One (1) coarse additive silo rotary feeder solid weigh scale.
(B) One (1) coarse additive screw conveyor discharging to the Fine Additive Production System.
(C) One (1) additive size reduction system, identified as Fine Additive Production System discharging to the fine additive silo (T33) or the Block 2000 coarse additive transfer system.

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(3) One (1) nitrogen-blanketed coarse additive transfer system, identified as Coarse Additive Screw Conveyor, approved in 2018 for construction, with a maximum capacity of 2.20 tons per hour, receiving material from the Block 1500 coarse additive silo and discharging to the Feed Premix Drum, with particulate emissions controlled by the Coarse Additive System Filter, exhausting to stack EU-2006.

(4) One (1) nitrogen-blanketed fine additive transfer system, identified as Fine Additive Handling System, approved in 2018 for construction, with a maximum capacity of 3.28 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Fine Additive System Filter, exhausting to stack EU-2007, consisting of:

(A) One (1) fine additive silo rotary feeder solid weigh scale.
(B) One (1) fine additive screw conveyor discharging to the Block 2000 feed premix drum.

(5) One (1) nitrogen-blanketed Na_2S slurry preparation system, identified as Na_2S Slurry

Preparation, approved in 2018 for construction, with a maximum capacity of 0.077 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Na_2S Handling System Filter, exhausting to stack EU-2008, consisting of:

(A) One (1) Na_2S silo rotary feeder solid weigh scale.
(B) One (1) Na_2S screw conveyor discharging to the Na_2S mixing drum.
(C) One (1) nitrogen-blanketed mixing drum for Na_2S and Block 2000 vacuum tower VGO (vacuum gas oil) discharging to the feed premix drum.

Under the NSPS, 40 CFR 60, Subpart GGGa, the mixing drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the mixing drum is an affected source.

(6) One (1) feed premix drum, identified as Feed Premix Drum, approved in 2018 for construction, receiving coal, solid additives, and recycled vacuum gas oil (VGO) and discharging to the feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed premix drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed premix drum is an affected source.

(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 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]

(a) Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the additive handling operations shall be as follows:

Emission Unit Description (ID)	**Control Device (Stack ID)**	**Emission Limitations**		
		Pollutant	**gr/dscf**	**lb/hr**
Coarse additive silo, T34 (EU-1501)	Baghouse EU-1501 (stack EU-1501)	PM	0.002	0.016
		PM_{10}	0.002	0.016
		$PM_{2.5}$	0.002	0.016
Fine additive silo, T33 (EU-1502)	Baghouse EU-1502 (stack EU-1502)	PM	0.002	0.018
		PM_{10}	0.002	0.018
		$PM_{2.5}$	0.002	0.018
Na_2S silo, T35 (EU-1503)	Baghouse EU-1503 (stack EU-1503)	PM	0.002	0.013
		PM_{10}	0.002	0.013
		$PM_{2.5}$	0.002	0.013
Fine additive production system	Baghouse EU-1504 (stack EU-1504)	PM	0.002	0.004
		PM_{10}	0.002	0.004
		$PM_{2.5}$	0.002	0.004

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	gr/dscf	lb/hr
Coarse additive screw conveyor	Coarse additive system filter (stack EU-2006)	PM	0.002	0.004
		PM_{10}	0.002	0.004
		$PM_{2.5}$	0.002	0.004
Fine additive transfer system	Fine additive system filter (stack EU-2007)	PM	0.002	0.004
		PM_{10}	0.002	0.004
		$PM_{2.5}$	0.002	0.004
Na_2S slurry preparation system	Na_2S handling system filter (stack EU-2008)	PM	0.002	0.001
		PM_{10}	0.002	0.001
		$PM_{2.5}$	0.002	0.001

PM_{10} and $PM_{2.5}$ include both filterable and condensable PM.

D.2.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.2.3 Particulate Control

(a) In order to assure compliance with Condition D.2.1, the following control devices for particulate control shall be in operation and control particulate emissions from the associated emission units at all times those emission units are in operation:

Emission Unit Description	Unit ID	Control Device ID
Coarse additive unloading	silo T34	Baghouse EU-1501
Fine additive unloading	silo T33	Baghouse EU-1502
Na_2S unloading	silo T35	Baghouse EU-1503
Fine additive production system	-	Baghouse EU-1504
Coarse additive transfer system	Coarse Additive Screw Conveyor	Filter EU-2006
Fine additive transfer system	Fine Additive Transfer	Filter EU-2007
Na_2S slurry preparation system	Na_2S Slurry Preparation	Filter EU-2008

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

D.2.4 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.2.1(a), not later than 180 days after the startup of the emission units listed in the table below, the Permittee shall perform PM, PM_{10}, and $PM_{2.5}$ testing of the emission units listed in the table below utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration.

Emission Unit	Control Device ID
Coarse additive unloading	Baghouse EU-1501
Fine additive unloading	Baghouse EU-1502
Na_2S unloading	Baghouse EU-1503
Fine additive production system	Baghouse EU-1504
Coarse additive transfer system	Filter EU-2006
Fine additive transfer system	Filter EU-2007
Na_2S slurry preparation system	Filter EU-2008

(b) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition. PM_{10} and $PM_{2.5}$ includes filterable and condensable PM.

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

D.2.5 Parametric Monitoring

The Permittee shall record the pressure drop across the baghouses and filters listed in the table below at least once per day when the associated emissions unit is in operation. When, for any one reading, the pressure drop across a baghouse or filter is outside the normal range, the Permittee shall take a reasonable response. The normal range for this unit is a pressure drop between 3.0 and 6.0 inches of water unless a different upper-bound or lower-bound value for this range is determined during the latest stack test. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

Control Device ID
Baghouse EU-1501
Baghouse EU-1502
Baghouse EU-1503
Baghouse EU-1504
Filter EU-2006
Filter EU-2007
Filter EU-2008

The instruments used for determining the pressure shall comply with Section C – Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months.

D.2.6 Broken or Failed Bag Detection

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

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

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

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

D.2.7 Record Keeping Requirement

(a) To document the compliance status with Condition D.2.5, the Permittee shall maintain daily records of pressure drop across the baghouses and filters. The Permittee shall include in its daily record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading (e.g. the process did not operate that day).

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

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS - Fuel Gas Combustion

Emissions Unit Description:

(b) Coal drying loop, collectively identified as EU-1008, with emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU -1008, consisting of the following:

(3) One (1) natural gas and process fuel gas-fired heater, identified as Coal Dryer Heater EU-1007, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 55.8 MMBtu/hr (HHV), with emissions exhausting to Stack EU-1007.

Under the NSPS, 40 CFR 60, Subpart Ja, the Coal Dryer Heater (EU-1007) is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Heater (EU-1007) is part of an affected thermal dryer.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, the Coal Dryer Heater (EU-1007) is an affected source.

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(7) One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2018 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

Under the NSPS, 40 CFR 60, Subpart Ja, the feed heater EU-2001 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed heater EU-2001 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed heater EU-2001 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, feed heater EU-2001 is an affected source.

(8) One (1) natural gas and process fuel gas-fired indirect treat gas heater, identified as EU-2002, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 52.8 MMBtu/hr (HHV), receiving hydrogen from Block 7000 and discharging to the 1st stage reactors, exhausting to stack EU-2002.

Under the NSPS, 40 CFR 60, Subpart Ja, the treat gas heater EU-2002 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, treat gas heater EU-2002 is an affected source.

(11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the

vacuum distillation tower, exhausting to stack EU-2003.

Under the NSPS, 40 CFR 60, Subpart Ja, the vacuum column feed heater EU-2003 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum column feed heater EU-2003 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum column feed heater EU-2003 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, vacuum column feed heater EU-2003 is an affected source.

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

Under the NSPS, 40 CFR 60, Subpart Db, fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, the fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator heater is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator heater is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, fractionator heater EU-2004 is an affected source.

(h) Utilities operations, identified as Block 6000, consisting of:

(1) One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 68.50 MMBtu/hr (HHV), exhausting to stack EU-6000.

Under the NSPS, 40 CFR 60, Subpart Dc, boiler EU-6000 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, boiler EU-6000 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, boiler EU-6000 is an affected source.

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

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

D.3.1 Prevention of Significant Deterioration (PSD) BACT [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (Control Technology Review; Requirements), the Permittee shall comply with the following requirements for the units listed in the table below:

Description	Unit ID
Coal dryer heater	EU-1007
Feed heater	EU-2001
Treat gas heater	EU-2002
Vacuum column feed heater	EU-2003
Fractionator heater	EU-2004
Package boiler	EU-6000

(a) The Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the fuel combustion units shall be as follows:

(1) The units shall burn only natural gas and process off-gas.

(2) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(3) Particulate matter emissions shall not exceed:

Emission Limitations			
Unit ID	**Pollutant**	**lb/MMBtu**	**lb/hr**
EU-1007	PM FILTERABLE	0.0019	0.11
	PM_{10}	0.0075	0.42
	$PM_{2.5}$	0.0075	0.42
EU-2001	PM FILTERABLE	0.0019	0.24
	PM_{10}	0.0075	0.96
	$PM_{2.5}$	0.0075	0.96
EU-2002	PM FILTERABLE	0.0019	0.10
	PM_{10}	0.0075	0.40
	$PM_{2.5}$	0.0075	0.40
EU-2003	PM FILTERABLE	0.0019	1.71E-02
	PM_{10}	0.0075	6.75E-02
	$PM_{2.5}$	0.0075	6.75E-02
EU-2004	PM FILTERABLE	0.0019	0.30
	PM_{10}	0.0075	1.17
	$PM_{2.5}$	0.0075	1.17
EU-6000	PM FILTERABLE	0.0019	0.13
	PM_{10}	0.0075	0.53
	$PM_{2.5}$	0.0075	0.53

PM_{10} and $PM_{2.5}$ include both filterable and condensable PM.

(b) The Best Available Control Technology (PSD BACT) for SO_2 for the fuel combustion units shall be as follows:

(1) The units shall burn only natural gas and process off-gas.

(2) The average sulfur content of the fuel gas combusted shall not exceed 0.005 gr/scf per twelve (12) consecutive month period with compliance determined at the end of each month.

(3) SO_2 emissions shall not exceed:

SO_2 Emission Limitations	
Unit ID	**tpy**
EU-1007	0.35
EU-2001	0.80
EU-2002	0.33
EU-2003	0.06
EU-2004	0.97
EU-6000	0.42

(c) The Best Available Control Technology (PSD BACT) for NOx for the fuel combustion units shall be as follows:

(1) The units shall burn only natural gas and process off-gas.

(2) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(3) The units shall use ultra-low-NOx burners.

(4) NOx emissions shall not exceed:

Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
EU-1007	0.030	1.67
EU-2001	0.030	3.85
EU-2002	0.030	1.58
EU-2003	0.030	0.27
EU-2004	0.030	4.68
EU-6000	0.030	2.06

(d) The Best Available Control Technology (PSD BACT) for VOC for the fuel combustion units shall be as follows:

(1) The units shall burn only natural gas and process off-gas.

(2) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(3) VOC emissions shall not exceed:

Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
EU-1007	0.0054	0.30
EU-2001	0.0054	0.69
EU-2002	0.0054	0.29
EU-2003	0.0054	0.05
EU-2004	0.0054	0.84
EU-6000	0.0054	0.37

(e) The Best Available Control Technology (PSD BACT) for CO for the fuel combustion units shall be as follows:

(1) The units shall burn only natural gas and process off-gas.

(2) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(3) CO emissions shall not exceed:

Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
EU-1007	0.0365	2.04
EU-2001	0.0365	4.69
EU-2002	0.0365	1.93
EU-2003	0.0365	0.33
EU-2004	0.0365	5.69
EU-6000	0.0365	2.50

(f) The Best Available Control Technology (PSD BACT) for carbon dioxide equivalent (CO_2e), as defined at 40 CFR 98.6, for the fuel combustion units shall be as follows:

(1) The units shall burn only natural gas and process off-gas.

(2) The units shall be designed and operated to achieve the highest practical energy efficiency.

(3) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained

within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(4) CO_2e emissions shall not exceed the value of tons per twelve (12) consecutive month period shown in the table below:

Emission Limitations	
Unit ID	**CO_2e Limit**
EU-1007	29,127
EU-2001	67,023
EU-2002	27,561
EU-2003	4,698
EU-2004	81,430
EU-6000	35,756

D.3.2 Air Quality Impact Requirements SO_2 [326 IAC 2-2-5]

Pursuant to 326 IAC 2-2-5 (Air Quality Impact; Requirements), sulfur content of the fuel gas and SO_2 emissions of the fuel gas combustion units listed in the table below shall not exceed the following:

Unit ID	**Sulfur Content (gr/scf)**	**SO_2 Emission Limitations (lb/hr)**
EU-1007	0.0063	0.10
EU-2001	0.0065	0.24
EU-2002	0.0064	0.10
EU-2003	0.0062	0.02
EU-2004	0.0063	0.28
EU-6000	0.0063	0.12

D.3.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.3.4 Testing Requirements [326 IAC 2-1.1-11]

In order to demonstrate compliance with Conditions D.3.1,

(a) Not later than 180 days after the startup of EU-1007, the Permittee shall perform PM, PM_{10}, $PM_{2.5}$, NOx, VOC, and CO testing of EU-1007 utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures).

(b) Not later than 180 days after the startup of EU-2001, the Permittee shall perform PM, PM_{10}, $PM_{2.5}$, VOC, and CO testing of EU-2001 utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures).

(c) Not later than 180 days after the startup of EU-2002, the Permittee shall perform PM, PM_{10}, $PM_{2.5}$, NOx, VOC, and CO testing of EU-2002 utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures).

(d) Not later than 180 days after the startup of EU-2003, the Permittee shall perform PM, PM_{10}, $PM_{2.5}$, NOx, VOC, and CO testing of EU-2003 utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures).

(e) Not later than 180 days after the startup of EU-2004, the Permittee shall perform PM, PM_{10}, $PM_{2.5}$, VOC, and CO testing of EU-2004 utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures).

(g) Not later than 180 days after the startup of EU-6000, the Permittee shall perform PM, PM_{10}, $PM_{2.5}$, NOx, VOC, and CO testing of EU-6000 utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures).

(g) Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition. PM_{10} and $PM_{2.5}$ includes filterable and condensable PM.

D.3.5 Continuous Emissions Monitoring [326 IAC 3-5] [326 IAC 2-7-6(1),(6)][40 CFR 60, Subpart Db] [40 CFR 60, Subpart Ja]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for EU-2001 and EU-2004 shall be calibrated, maintained, and operated for measuring NO_X and O_2 (or CO_2 in the case of EU-2004), which meet all applicable performance specifications of 326 IAC 3-5-2.

(b) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

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

D.3.6 Continuous Oxygen Monitoring [326 IAC 3-5] [326 IAC 2-7-6(1),(6)][40 CFR 60, Subpart Ja]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous O_2 monitoring systems for EU-1007, EU-2002, and EU-6000 shall be calibrated, maintained, and operated for measuring O_2, which meet all applicable performance specifications of 326 IAC 3-5-2.

(b) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

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

D.3.7 Continuous Monitoring

(a) In order to demonstrate compliance with Condition D.3.1(b)(2), the Permittee shall install Total Sulfur Continuous Analyzers on the fuel gas to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in the emission units listed in the following table. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor fuel gas locations that accurately represent the total sulfur concentration in the fuel gas being burned in all heaters and boilers, other than fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

Emission Unit	Unit ID
Coal dryer heater	EU-1007
Feed heater	EU-2001
Treat gas heater	EU-2002
Vacuum column feed heater	EU-2003
Fractionator heater	EU-2004
Package boiler	EU-6000

(b) The Total Sulfur Continuous Analyzer shall be calibrated, maintained, and operated for measuring total sulfur in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment. The SO_2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO_2

D.3.8 Greenhouse Gases (GHGs)

To determine the compliance status with Condition D.3.1(f)(4), the following equation shall be used to determine the CO_2e emissions from EU-1007, EU-2001, EU-2002, EU-2003, EU-2004, and EU-6000:

$$E_{GHGi} = F_i \times 60.12\ {}^{tons}/_{MMCF}$$

Where E_{GHGi} = CO_2e emissions for unit *i*, tons/month
F_i = fuel gas usage in unit *i*, MMCF/month
i = fuel combustion unit ID

Compliance Monitoring Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-19]

D.3.9 NO_X, and O_2 or CO_2 Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a NO_X and O_2 or CO_2 continuous emissions monitoring system (CEMS) for EU-2004 occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

D.3.10 NO_X, and O_2 Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a NO_X, and O_2 continuous emissions monitoring system (CEMS) for EU-2001 occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NO_X, and O_2 continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NO_X, and O_2 CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NO_X, and O_2 CEMS, the Permittee shall comply with the following:

  (1) The Permittee shall monitor and record stack percent oxygen to demonstrate that the operation of the unit continues in a typical manner. These parametric monitoring readings shall be recorded at least once per day until the primary CEM or backup CEM is brought online

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during normal operations, with at least four (4) hours between each set of readings, until a NO_X, and O_2 CEMS is online.

D.3.11 O_2 Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a O_2 continuous emissions monitoring system (CEMS) for EU-1007, EU-2002, or EU-6000 occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a O_2 continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup O_2 CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary O_2 CEMS, the Permittee shall comply with the following:

  (1) The Permittee shall monitor and record stack percent oxygen to demonstrate that the operation of the unit continues in a typical manner. These parametric monitoring readings shall be recorded at least once per day until the primary CEM or backup CEM is brought online

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during normal operations, with at least four (4) hours between each set of readings, until a O_2 CEMS is online.

D.3.12 Total Sulfur Continuous Analyzer Equipment Downtime

(a) Whenever a Total Sulfur Continuous Analyzer is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup Total Sulfur Continuous Analyzer is not online within twenty-four (24) hours of shutdown or malfunction of the primary Total Sulfur Continuous Analyzer, the Permittee shall comply with the following:

  (1) The Permittee shall measure and record Draeger tube sampling of the fuel gas one time per hour until the primary Total Sulfur Continuous Analyzer or a backup Total Sulfur Continuous Analyzer is brought online.

(b) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time.

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

D.3.13 Record Keeping Requirement

(a) To document the compliance status with Condition D.3.1(f)(4), the Permittee shall maintain records in accordance with (1) through (3) below. Records maintained for (1) through (3) shall be taken monthly and shall be complete and sufficient to establish compliance with the emission limits established in Condition D.3.1(f)(4).

(1) Calendar dates covered in the compliance determination period.
(2) Fuel usage for EU-1006, EU-2001, EU-2002, EU-2003, EU-2004, and EU-6000.
(3) Monthly records of the CO_2e emissions.

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

D.3.14 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(B)] [326 IAC 3-5]

(a) The Permittee shall record the output of the NOx continuous monitoring system(s) pound per hour and shall perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the NOx continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

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

D.3.15 Record Keeping Requirements for O_2 CEMS [326 IAC 2-7-5(3)(B)] [326 IAC 3-5]

(a) The Permittee shall record the output of the O_2 continuous monitoring system(s) pound per hour and shall perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the O_2 continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

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

D.3.16 Record Keeping Requirements for Continuous Monitoring Equipment

(a) The Permittee shall record the output of the Total Sulfur Continuous Analyzers in grain per standard cubic foot on an hourly average, monthly average and twelve (12) month average.

(b) To document the compliance status with Condition D.3.12(a)(1) the Permittee shall maintain hourly records of the Draeger tube sampling of the fuel gas. The Permittee shall include in its record when the readings are not taken and the reason for the lack of the readings (e.g., the process did not operate that day).

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

D.3.17 Reporting Requirements

(a) A quarterly report of CO_2e emissions and a quarterly summary of the information to document the compliance status with Condition D.3.1(f)(4) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting Requirements contains the Permittee’s obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1(35).

D.3.18 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) The Permittee shall prepare and submit to IDEM, OAQ a written report of the results of the calibration gas audits and relative accuracy test audits for each calendar quarter within thirty (30) calendar days after the end of each quarter. The report must contain the information required by 326 IAC 3-5-5(f).

(b) Pursuant to 326 IAC 3-5-7(5), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;
(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

(c) The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1 (35).

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS - Sulfur Recovery

Emissions Unit Description:

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

(A) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the HP Absorber and LP Absorber are affected sources.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the HP Absorber and LP Absorber is an affected source.

(e) Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

(A) One (1) heat exchanger, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) stripper column , identified as Stripper, approved in 2018 for construction, discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger and the reboiler and vapor to the overheads condenser, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(C) One (1) water-cooled condenser, identified as Overheads Condenser, approved in 2018 for construction, discharging condensate to the stripper condenser accumulator, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(D) One (1) accumulator drum, identified as Stripper Condenser Accumulator, approved in 2018 for construction, discharging condensate to stripper reflux and the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(E) One (1) steam-heated reboiler, identified as Stripper Reboiler, approved in 2018 for construction, discharging lean amine to the stripper reflux, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Amine Recovery Unit is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Amine Recovery Unit part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Amine Recovery Unit is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Amine Recovery Unit is an affected source.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 61, Subpart FF, the Sour Water Stripping System is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Sour Water Stripping System is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Sour Water Stripping System is an affected source.

(3) Sulfur Recovery System, consisting of:

(A) One (1) Sulfur Recovery Unit A, identified as EU-3001, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

- (i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
- (ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.
- (iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
- (iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the TGTU A heat exchanger and molten sulfur to the sulfur product pit.
- (v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
- (vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
- (vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
- (viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
- (ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
- (x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
- (xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

  Under the NSPS, 40 CFR 60, Subpart Dc, the A-605A Incinerator and A-605A Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit A is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit A is an affected source.

(B) One (1) Sulfur Recovery Unit B, identified as EU-3002, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

- (i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
- (ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.
- (iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
- (iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.
- (v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
- (vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
- (vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.
- (viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
- (ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
- (x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
- (xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

  Under the NSPS, 40 CFR 60, Subpart Dc, the A-605B Incinerator and A-605B Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit B is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit B is an affected source.

(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 Prevention of Significant Deterioration (PSD) BACT [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (Control Technology Review; Requirements), the Permittee shall comply with the following requirements for the sulfur recovery units:

(a) PM (filterable) emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0019 lb/MMBtu and 0.10 lb/hr, each.

(b) PM_{10} emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0074 lb/MMBtu and 0.39 lb/hr, each.

(c) $PM_{2.5}$ emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0074 lb/MMBtu and 0.39 lb/hr, each.

(d) The SO_2 emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 150 ppmv @ 0% excess air (on a twelve month rolling average) and shall be less than 167 ppmv @ 0% excess air (on a twelve hour average).

(e) The SO_2 emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 26.30 lb/hr, each.

(f) The tail gas treatment units (TGTUA and TGTUB) shall each use low-NOx burners.

(g) NOx emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.10 lb/MMBtu and 5.28 lb/hr, each.

(h) VOC emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0054 lb/MMBtu and 0.28 lb/hr, each.

(i) CO emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 65 ppmv @ 0% O_2, shall not exceed 0.082 lb/MMBtu and 4.33 lb/hr, each.

(j) Sulfuric Acid Mist (H_2SO_4 mist) emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0244 lb/MMBtu and 1.29 lb/hr, each.

(k) Opacity shall not exceed ten percent (10%) on a six-minute average.

(l) Incinerators (A-605A and A-605B) shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(m) Carbon dioxide equivalent (CO_2e) emissions, as defined at 40 CFR 98.6, from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 40,872 tons per twelve (12) consecutive month period, combined, with compliance determined at the end of each month.

D.4.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.4.3 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.4.1(a), (b), (c), (g), (h), (i), and (j), not later than 180 days after the startup of EU-3001, the Permittee shall perform PM, PM_{10}, $PM_{2.5}$, NOx, VOC, CO, and sulfuric acid mist testing of EU-3001 utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration.

(b) In order to demonstrate compliance with Condition D.4.1(a), (b), (c), (g), (h), (i), and (j), not later than 180 days after the startup of EU-3002, the Permittee shall perform PM, PM_{10}, $PM_{2.5}$, NOx, VOC, CO, and sulfuric acid mist testing of EU-3002 utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration.

(c) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition. PM10 and PM2.5 includes filterable and condensable PM.

D.4.4 Continuous Emissions Monitoring [326 IAC 3-5] [326 IAC 2-7-6(1),(6)]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for tail gas incinerators A-605A and A-605B shall be calibrated, maintained, and operated for measuring SO_2 which meet all applicable performance specifications of 326 IAC 3-5-2.

(b) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for tail gas incinerators A-605A and A-605B shall be calibrated, maintained, and operated for measuring oxygen for correcting the SO_2 data for excess air which meet all applicable performance specifications of 326 IAC 3-5-2.

(c) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

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

D.4.5 Greenhouse Gases (GHGs)

To determine the compliance status with Condition D.4.1(l), the following equation shall be used to determine the CO_2e emissions from EU-3001 and EU-3002:

$$E_{GHGSB} = \text{Sulfur production (tons/month)} \times 0.641 \text{ (ton } CO_2e\text{/ton S)}$$

Where:

E_{GHGSB} = CO_2e emissions (ton/month) for the sulfur recovery systems (TGTUA and TGTUB)

Compliance Monitoring Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-19]

D.4.6 SO_2 Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a SO_2 continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a SO_2 continuous emissions monitoring system (CEMS) is malfunctioning or is down for calibration, maintenance, or repairs for a period of twenty-four (24) hours or more and a backup SO_2 CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary SO_2 CEMS, the Permittee shall comply with the following:

(1) The Permittee shall measure and record Draeger tube sampling of the hydrogen sulfide (H_2S) concentration in amine absorber T-602A or T-602B (as required) offgas to incinerator. These parametric monitoring readings shall be recorded at least once per hour until the primary CEMS or backup CEMS is brought online.

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction.

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

D.4.7 Record Keeping Requirement

(a) To document the compliance status with Condition D.4.1(l), the Permittee shall maintain records in accordance with (1) through (3) below. Records maintained for (1) through (3) shall be taken monthly and shall be complete and sufficient to establish compliance with the emission limits established in Condition D.4.1(n).

(1) Calendar dates covered in the compliance determination period.
(2) Sulfur production for Sulfur Recovery Unit A and Sulfur Recovery Unit B.
(3) Monthly records of the CO_2e emissions.

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

D.4.8 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(B)] [326 IAC 3-5]

(a) The Permittee shall record the output of the continuous monitoring system(s) SO_2 concentration (dry basis, zero percent excess air) and shall perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the SO_2 or oxygen continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(c) To document the compliance status with Condition D.4.6(b)(1) the Permittee shall maintain daily records of the inlet H_2S and concentration of the tail gas incinerator. The Permittee shall include in its daily record when the readings are not taken and the reason for the lack of the readings (e.g., the process did not operate that day).

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

D.4.9 Reporting Requirements

A quarterly report of CO_2e emissions and a quarterly summary of the information to document the compliance status with Condition D.4.1(l) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official," as defined by 326 IAC 2-7-1(35).

D.4.10 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) The Permittee shall prepare and submit to IDEM, OAQ a written report of the results of the calibration gas audits and relative accuracy test audits for each calendar quarter within thirty (30) calendar days after the end of each quarter. The report must contain the information required by 326 IAC 3-5-5(f).

(b) Pursuant to 326 IAC 3-5-7(5), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;

(2) time of commencement;

(3) duration of each downtime;

(4) reasons for each downtime; and

(5) nature of system repairs and adjustments.

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

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS - Flares

Emissions Unit Description:

(f) Offsites operations, identified as Block 4000, consisting of:

(1) Flares, as follows:

(A) One (1) natural gas and process fuel gas-fired flare identified as High Pressure (HP) Flare, approved in 2018 for construction, servicing overpressure and emergency reliefs from Block 2000 VEBA Combi Cracker operations, controlling emissions from Block 2000 depressurization system, with pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(B) One (1) natural gas and process fuel gas-fired flare, identified as Low Pressure (LP) Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 7000 Hydrogen Unit operations, controlling emissions Block 7000 start-up and shut-down vents, and a continuous sweep stream from the Block 2000 slop tank, with a sweep and pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(C) One (1) natural gas and process fuel gas-fired flare, identified as Sulfur Block Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 3000 Sulfur Recovery operations and sulfur loading, controlling emergency streams from Sulfur Recovery Units A and B, and a continuous sweep stream from the sour water storage tanks, with a sweep and pilot heat input capacity of 0.77 MMBtu/hr (LHV), exhausting to the atmosphere.

Under the NSPS, 40 CFR 60, Subpart Ja, the flares are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, the flares are affected facilities.

Under the NESHAP, 40 CFR 63, Subpart CC, the flares are affected sources.

(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 Prevention of Significant Deterioration (PSD) BACT [326 IAC 2-2-3] [326 IAC 8-1-6]

Pursuant to 326 IAC 2-2-3 (Control Technology Review; Requirements), the Best Available Control Technology (PSD BACT) for the flares is determined to be:

(a) The units shall burn only natural gas and process off-gas as supplemental and pilot fuel.

(b) The Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the flares shall be as follows:

(1) Particulate matter emissions while operating in sweep and pilot mode shall not exceed:

Emission Limitations			
Unit ID	**Pollutant**	**lb/MMBtu**	**lb/hr**
HP Flare	PM FILTRABLE	0.0019	0.014
	PM_{10}	0.0074	0.053
	$PM_{2.5}$	0.0074	0.053
LP Flare	PM FILTRABLE	0.0019	0.014
	PM_{10}	0.0074	0.053
	$PM_{2.5}$	0.0074	0.053
SB Flare	PM FILTRABLE	0.0019	1.62E-03
	PM_{10}	0.0074	6.32E-03
	$PM_{2.5}$	0.0074	6.32E-03

(2) The HP Flare and LP Flare shall operate with no visible emissions, except for periods not to exceed a total of five (5) minutes during any two (2) consecutive hours when flaring a process stream.

(c) The Best Available Control Technology (PSD BACT) for SO_2 for the flares shall be as follows:

(1) The Permittee shall burn only natural gas and process off-gas in any flare as supplemental or pilot fuel gas.

(2) SO_2 emissions while operating in sweep and pilot mode shall not exceed:

SO_2 Emission Limitations	
Unit ID	**lb/hr**
HP Flare	0.013
LP Flare	0.013

(3) SO_2 emissions from the SB Flare shall not exceed 0.069 lb/hr when operating in sweep and pilot mode.

(d) The Best Available Control Technology (PSD BACT) for NOx for the flares shall be as follows:

(1) NOx emissions while operating in sweep and pilot mode shall not exceed:

NOx Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
HP Flare	0.099	0.71
LP Flare	0.099	0.71
SB Flare	0.099	8.46E-02

(2) NOx emissions shall not exceed 0.068 lb/MMBtu (LHV) when flaring a process stream.

(e) The Best Available Control Technology (PSD BACT) for VOC for the flares shall be as follows:

(1) VOC emissions while operating in sweep and pilot mode shall not exceed:

VOC Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
HP Flare	0.0054	0.039
LP Flare	0.0054	0.039
SB Flare	0.0054	4.62E-03

(2) VOC destruction and removal efficiency shall not be less than 98% when flaring a process stream.

(f) The Best Available Control Technology (PSD BACT) for CO for the flares shall be as follows:

(1) CO emissions while operating in sweep and pilot mode shall not exceed:

CO Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
HP Flare	0.083	0.60
LP Flare	0.083	0.60
SB Flare	0.083	7.09E-02

(2) CO emissions shall not exceed 0.31 lb/MMBtu (LHV) when flaring a process stream.

(g) Carbon dioxide equivalent (CO_2e) emissions, as defined at 40 CFR 98.6, from the flares listed in the table below when operating in sweep and pilot mode shall not exceed the values shown per twelve (12) consecutive month period, with compliance determined at the end of each month.

Emission Limitations	
Unit ID	**CO_2e Limit**
Sulfur Block Flare	448
LP Flare	3,781
HP Flare	3,781

D.5.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.5.3 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.5.1, during the first planned event that provides suitable conditions for testing one or more of the flares, the Permittee shall determine the net heating value of the gas being combusted, the actual exit velocity of each flare, and visible emissions listed in the table below utilizing methods approved by the commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

Description
HP Flare
LP Flare
Sulfur Block Flare

(b) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.5.4 Continuous Monitoring

(a) In order to demonstrate compliance with Conditions D.5.1(c), the Permittee shall install Total Sulfur Continuous Analyzers for any gas stream vented to the flare to continuously monitor, measure and record the total sulfur concentration of flared streams, sweep gases, supplemental fuel, and pilot fuel burned in the HP Flare, LP Flare, and SB Flare. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor gas streams at locations that accurately represent the total sulfur concentration in the gas streams being burned in all flares, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

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

(b) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

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

D.5.5 Greenhouse Gases (GHGs)

To determine the compliance status with Condition D.5.1(g), the following equation shall be used to determine the CO_2e emissions from the HP Flare, LP Flare, and Sulfur Block Flare:

$$E_{FLAi} = F_i \text{ (MMCF/month) x 60.36 (ton } CO_2e\text{/MMCF fuel gas)}$$

Where:

E_{FLAi} = CO_2e emissions for flare *i*, (ton/month)
F_i = Monthly sweep and pilot fuel gas usage in flare *i*, (MMCF/month)
i = flare identifier

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

D.5.6 Flare Pilot Flame

In order to assure compliance with Condition D.5.1, the Permittee shall monitor the presence of a pilot flame in the flares listed in the table below using a thermocouple or any other equivalent device to detect the presence of a flame.

Description
HP Flare
LP Flare
Sulfur Block Flare

D.5.7 Total Sulfur Continuous Analyzer Equipment Downtime

(a) Whenever a Total Sulfur Continuous Analyzer is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup Total Sulfur Continuous Analyzer is not online within twenty-four (24) hours of shutdown or malfunction of the primary Total Sulfur Continuous Analyzer, the Permittee shall comply with the following:

(1) The Permittee shall measure and record Draeger tube sampling of the flare gas stream one time per hour until the primary CEMS or a backup CEMS is brought online.

(b) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time.

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 Condition D.5.1(b)(2), (d)(2), (e)(2) and (f)(2), the Permittee shall maintain records, such as calculations and plans, demonstrating that the HP Flare, LP Flare, and SU Flare were designed to comply with 40 CFR 60.18.

(b) To document the compliance status with Condition D.5.1(g), the Permittee shall maintain records in accordance with (1) through (3) below. Records maintained for (1) through (3) shall be taken monthly and shall be complete and sufficient to establish compliance with the emission limits established in Condition D.5.1(g).

(1) Calendar dates covered in the compliance determination period.
(2) Monthly sweep and pilot usage of fuel gas in:
    (A) HP Flare
    (B) LP Flare
    (C) Sulfur Block Flare

(3) Monthly records of the CO_2e emissions.

(c) To document the compliance status with Condition D.5.6, the Permittee shall maintain records of temperature or other parameters sufficient to demonstrate the presence of a pilot flame when each flare is in operation.

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

D.5.9 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(B)] [326 IAC 3-5]

(a) The Permittee shall record the output of the Total Sulfur Continuous Analyzer ppmvd and shall perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the Total Sulfur Continuous Analyzer occurs, the Permittee shall maintain records of all malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(c) To document the compliance status with Condition D.5.7(a)(1) the Permittee shall maintain hourly records of the Draeger tube sampling of the flare gas. The Permittee shall include in its record when the readings are not taken and the reason for the lack of the readings (e.g., the process did not operate that day).

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

D.5.10 Reporting Requirements

A quarterly report of CO_2e emissions and a quarterly summary of the information to document the compliance status with Condition D.5.1(g) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting Requirements contains the Permittee’s obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1(35).

D.5.11 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) The Permittee shall prepare and submit to IDEM, OAQ a written report of the results of the calibration gas audits and relative accuracy test audits for each calendar quarter within thirty (30) calendar days after the end of each quarter. The report must contain the information required by 326 IAC 3-5-5(f).

(b) Pursuant to 326 IAC 3-5-7(5), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;
(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

(c) The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1 (35).

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS - Tanks

Emissions Unit Description:

(f) Offsites operations, identified as Block 4000, consisting of:

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Pressure Relief Control[2]
T1	IFR	Naphtha product	4,629,879 (17,524)	-
T2	IFR	Naphtha product	4,629,879 (17,524)	-
T3	FR	Diesel product	4,525,796 (17,130)	-
T4	FR	Diesel product	4,525,796 (17,130)	-
T5	FR	Diesel product	4,525,796 (17,130)	-
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)	-
T7	FR	Molten sulfur	342,367 (1,296)	-
T8	FR	Molten sulfur	342,367 (1,296)	-
T9	HPV	Ammonia product	36,720 (17,524)	-
T10	FR	Residue surge tank 1	926,980 (17,524)	-
T11	FR	Residue surge tank 2	926,980 (3,509)	-
T12	FR	Residue feed tank	926,980 (3,509)	-
T13	FR	VGO tank 1	926,980 (3,509)	-
T14	FR	VGO tank 2	926,980 (3,509)	-
T15	HPV	LPG storage	48,872 (185)	-
T16	FR	Slop tank	4,195,581 (15,880)	LP flare
T17	FR	Diesel fuel tank	23,775 (90)	-
T18	FR	Non-phenolic sour water storage tank 1	1,268,026 (4,799)	SB flare
T19	FR	Non-phenolic sour water storage tank 2	1,268,026 (4,799)	SB flare
T20	FR	Non-phenolic sour water storage tank 3	1,268,026 (4,799)	SB flare
T21	FR	Phenolic sour water storage tank	40,947 (155)	SB flare

T22	FR	Stripped non-phenolic sour water surge tank	1,268,026 (4,799)	-
T23	FR	Stripped phenolic sour water surge tank	13,737 (52)	-
T24	FR	Amine surge/deinventory tank	63,943 (242)	-
T25	FR	Fresh amine tank	63,943 (242)	-
T26	FR	Amine containment tank (sump)	793 (3)	-

1. *FR - fixed roof, IFR - internal floating roof, HPV-horizontal pressure vessel*
2. *Tank vents to flares are part of sweep and pilot gas streams.*

Under the NSPS, 40 CFR 60, Subpart Kb, T1, T2, and T6 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, T1 - T6 and T10 - T15 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart QQQ, T16 is part of an affected facility.

Under the NSPS, 40 CFR 61, Subpart FF, T16 and T18 - T21 are part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, T1 - T6, T10 - T15, T16, and T18-T23 are part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart WW, T3 - T6 and T10 - T15 are affected sources.

Insignificant Activities

(l) An emission unit or activity whose potential uncontrolled emissions meet the exemption levels specified in 326 IAC 2-1.1-3(e)(1) or the exemption levels specified in the following, whichever is lower:

- For lead or lead compounds measured as elemental lead, the exemption level is six-tenths (0.6) ton per year or three and twenty-nine hundredths (3.29) pounds per day.
- For carbon monoxide (CO), the exemption limit is twenty-five (25) pounds per day.
- For sulfur dioxide, the exemption level is five (5) pounds per hour or twenty-five (25) pounds per day.
- For VOC, the exemption limit is three (3) pounds per hour or fifteen (15) pounds per day.
- For nitrogen oxides (NOx), the exemption limit is five (5) pounds per hour or twenty-five (25) pounds per day.
- For PM10 or direct PM2.5, the exemption level is either five (5) pounds per hour or twenty-five (25) pounds per day.

As follows:

(2) One (1) emergency generator fuel tank, identified as EU-6005, approved in 2018 for construction, with a nominal capacity of 2,000 gallons and an expected annual throughput of 69,450 gallons, using no controls and exhausting to stack EU-6005.

(3) One (1) emergency fire pump fuel tank, identified as EU-6007, approved in 2018 for construction, with a nominal capacity of 500 gallons and an expected annual

throughput of 19,950 gallons, using no controls and exhausting to stack EU-6007.

(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.6.1 Prevention of Significant Deterioration (PSD) Best Available Control Technology BACT)[326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (Control Technology Review; Requirements), the Permittee shall comply with the following:

(a) VOL (as defined at 40 CFR 60.111b) tanks, T1, T2, and T6, shall use internal floating roofs.
(b) Emissions from the slop tank, T16, shall be controlled by the LP Flare at all times and the slop tank throughput shall not exceed the value shown in the table below per twelve (12) consecutive month period with compliance determined at the end of each month.
(c) Emissions from the sour water tanks, T18 - T21, shall be controlled by the Sulfur Block Flare at all times and the sour water tank throughputs shall each not exceed the values shown in the table below per twelve (12) consecutive month period with compliance determined at the end of each month.
(d) All tanks shall use white tank shells.
(e) All tanks shall use submerged filling.
(f) All tanks shall use good maintenance practices based on generally-accepted industry standards, including but not limited to API 650 Welded Steel Tanks for Oil Storage and API 653 Tank Inspection, Repair, Alteration, and Reconstruction.
(g) Tanks shall comply with the following limitations:

Tank ID	Product Stored	Storage Temperature (°F)	VOC Emissions Limit (tons/yr)	Throughput Limit (kgal/yr)
T1	Naphtha Product	ambient	1.15	-
T2	Naphtha Product	ambient	1.15	-
T3	Diesel Product	ambient	2.29	-
T4	Diesel Product	ambient	2.29	-
T5	Diesel Product	ambient	2.29	-
T6	Naphtha Product	ambient	1.15	-
	Diesel Product	ambient	0.17	-
T10	Residue	505	1E-04	-
T11	Residue	505	1E-04	-
T12	Residue	505	1E-04	-
T13	VGO	505	0.175	-
T14	VGO	505	0.175	-
T16	Slop tank	ambient	-	305,467
T17	Diesel Fuel	ambient	1.14E-02	-
T18	Non-Phenolic Sour Water	ambient	-	462,829
T19	Non-Phenolic Sour Water	ambient	-	462,829
T20	Non-Phenolic Sour Water	ambient	-	462,829
T21	Phenolic Sour Water	ambient	-	4,628
T22	Stripped Non-Phenolic Sour Water	ambient	0.48	-
T23	Stripped Phenolic Sour Water	ambient	0.48	-
T24	Amine Surge/Deinventory	ambient	0.48	-
T25	Fresh Amine	ambient	0.48	-

Tank ID	Product Stored	Storage Temperature (°F)	VOC Emissions Limit (tons/yr)	Throughput Limit (kgal/yr)
T26	Amine Containment	ambient	0.48	-
EU-6005	Emergency generator diesel fuel	ambient	1.14E-02	-
EU-6008	Emergency fire pump diesel fuel	ambient	1.14E-02	-

D.6.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.6.3 VOC Control

(a) In order to assure compliance with Condition D.6.1(g), the LP Flare for VOC control shall be in operation and control VOC emissions from the slop tank at all times the slop tank is in operation.

(b) In order to assure compliance with Condition D.6.1(g), the Sulfur Block Flare for hydrogen sulfide control shall be in operation and control hydrogen sulfide emissions from sour water tanks T18 - T21 at all times sour water tanks T18 - T21 are in operation.

D.6.4 Swing Tank Product Changes

(a) In any twelve (12) consecutive month period during which tank T6 does not change between naphtha and diesel service, tank T6 shall be determined to be in compliance with the VOC emission limit in the table in Condition D.6.1 for the product in service.

(b) In any twelve (12) consecutive month period during which tank T6 changes between naphtha and diesel service, tank T6 shall be determined to in compliance with the VOC emission limit in Condition D.6.1 if the result, C, of the calculation below is less than or equal to 1.

$$C = \frac{D_N \times 6.29}{2{,}295} + \frac{(365 - D_N) \times 0.95}{345}$$

Where C = compliance determination coefficient
D_N = actual number of days in naphtha service during the twelve (12) consecutive month period

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

D.6.5 Record Keeping Requirements

(a) To document the compliance status with Condition D.6.1(b), the Permittee shall maintain records of the monthly slop oil throughput in tank T16.

(b) To document the compliance status with Condition D.6.1(c), the Permittee shall maintain records of the monthly sour water throughput in each of tanks T18 - T21.

(c) To document the compliance status with Condition D.6.1(g), the Permittee shall maintain daily records of the type of product stored in swing tank T6.

(d) To document the compliance status with Condition D.6.1(g) for tank T6 in any twelve (12) month period when the tank changes between naphtha and diesel service, the Permittee shall maintain records of the compliance determination calculation in Condition D.6.4(b).

(e) To document the compliance status with Condition D.6.1(f), the Permittee shall maintain records of maintenance activity performed on the tanks listed in the table in Condition D.6.1, including but not limited to, inspections and repairs.

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

D.6.6 Reporting Requirements

(a) A quarterly report of slop tank throughput and a quarterly summary of the information to document the compliance status with Condition D.6.1(b) shall be submitted not later than thirty (30) days after the end of the quarter being reported.

(b) A quarterly report of throughput in each of sour water tanks T18 - T21 and a quarterly summary of the information to document the compliance status with Condition D.6.1(c) shall be submitted not later than thirty (30) days after the end of the quarter being reported.

(c) A quarterly report of days in naphtha service for swing tank T6 and a quarterly summary of the information to document the compliance determination requirements in Condition D.6.4 shall be submitted not later than thirty (30) days after the end of the quarter being reported.

(d) Section C - General Reporting Requirements contains the Permittee’s obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1(35).

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS - Product Loadout

Emissions Unit Description:

(f) Offsites operations, identified as Block 4000, consisting of:

(1) Flares, as follows:

(D) One (1) natural gas and process fuel gas-fired flare, identified as Loading Flare, approved in 2018 for construction, servicing Block 4000 naphtha, diesel, and ammonia loading operations, with a pilot heat input capacity of 0.20 MMBtu/hr (LHV), exhausting to the atmosphere.

Under the NSPS, 40 CFR 60, Subpart Ja, the flares are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, the flares are affected facilities.

Under the NESHAP, 40 CFR 63, Subpart CC, the flares are affected sources.

(3) Loading operations, as follows:

(A) One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Product Loading Rack is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart BB, the Product Loading Rack is an affected source.

Under the NESHAP, 40 CFR 63, Subpart CC, the Product Loading Rack is an affected source.

(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.7.1 Prevention of Significant Deterioration (PSD) BACT [326 IAC 2-2-3] [326 IAC 8-1-6]

Pursuant to 326 IAC 2-2-3 (Control Technology Review; Requirements), the Permittee shall comply with the following:

(a) The Loading Flare shall burn only natural gas and process off-gas as supplemental and pilot fuel.

(b) The Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the Loading Flare shall be as follows:

(1) Particulate matter emissions while operating pilot mode shall not exceed:

Emission Limitations			
Unit ID	**Pollutant**	**lb/MMBtu**	**lb/hr**
Loading Flare	PM FILTRABLE	0.0019	4.22E-04
	PM_{10}	0.0074	1.64E-03
	$PM_{2.5}$	0.0074	1.64E-03

(c) The Best Available Control Technology (PSD BACT) for SO_2 for the Loading Flare shall be as follows:

(1) The Permittee shall burn only natural gas and process off-gas in any flare as supplemental or pilot fuel gas

(2) SO_2 emissions from the Loading Flare shall not exceed 0.069 lb/hr when operating in pilot mode.

(d) The Best Available Control Technology (PSD BACT) for NOx for the Loading Flare shall be as follows:

(1) NOx emissions while operating in pilot mode shall not exceed:

NOx Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
Loading Flare	0.099	2.20E-02

(2) NOx emissions shall not exceed 0.068 lb/MMBtu (LHV) when controlling emissions from naphtha or diesel loading operations.

(e) The Best Available Control Technology (PSD BACT) for VOC for the Loading Flare shall be as follows:

(1) VOC emissions while operating in pilot mode shall not exceed:

VOC Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
Loading Flare	0.0054	1.20E-03

(2) The Product Loading Rack shall use only submerged loading.

(3) The overall VOC control efficiency, including capture efficiency and destruction efficiency, for the Product Loading Flare shall be 98% or greater.

(4) VOC emissions shall not exceed:

Emission Limitations	
Product	**lb/kgal[1]**
naphtha	0.049
diesel	1.02E-03

1. kgal = 1,000 gallons

(f) The Best Available Control Technology (PSD BACT) for CO for the Loading Flare shall be as follows:

(1) CO emissions while operating in pilot mode shall not exceed:

CO Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
Loading Flare	0.083	1.84E-02

(2) CO emissions shall not exceed 0.31 lb/MMBtu (LHV) when flaring a process stream.

(g) Carbon dioxide equivalent (CO_2e) emissions, as defined at 40 CFR 98.6, from the Loading Flare shall not exceed 559 tons per twelve (12) consecutive month period, combined, with compliance determined at the end of each month.

D.7.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.7.3 Flare Compliance Determination

(a) The Loading Flare shall be determined to be in compliance with Conditions D.7.1(b)(1), (d)(1), (e)(1), and (f)(1) at all times that the flares burn only gaseous fuel that complies with Condition D.7.1(c).

(b) Prior to such time as the source shall conduct the testing required in Condition D.7.5, the Loading Flare shall be determined to be in compliance with Condition D.7.1(c)(2), (d)(2), and (f)(2) at all times that the source can demonstrate that the flares were designed to comply with 40 CFR 60.18.

D.7.4 VOC Control

In order to assure compliance with Condition D.7.1, the Loading Flare for VOC control shall be in operation and control emissions from the Product Loading Rack facility at all times the Product Loading Rack facility is in operation.

D.7.5 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.7.1, not later than 180 days after the startup of the Product Loading Flare, the Permittee shall determine the net heating value of the gas being combusted, the actual exit velocity of each flare, and visible emissions while loading naphtha utilizing methods approved by the commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(b) In order to demonstrate compliance with Condition D.7.1, not later than 180 days after the startup of the Product Loading Flare, the Permittee shall determine the net heating value of the gas being combusted, the actual exit velocity of each flare, and visible emissions while loading diesel utilizing methods approved by the commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(c) In order to demonstrate compliance with Condition D.7.1, not later than 180 days after the startup of the Product Loading Rack, the Permittee shall perform VOC input rate testing of the Product loading flare while loading naphtha utilizing methods approved by the commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(d) In order to demonstrate compliance with Condition D.7.1, not later than 180 days after the startup of the Product Loading Rack, the Permittee shall VOC input rate testing of the Product loading flare while loading diesel utilizing methods approved by the commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(e) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.7.6 Continuous Monitoring

(a) In order to demonstrate compliance with Conditions D.7.1(c)(2), the Permittee shall install Total Sulfur Continuous Analyzers for any gas stream vented to the flare to continuously monitor, measure and record the total sulfur concentration of flared streams, sweep gases, supplemental fuel, and pilot fuel burned in the Loading Flare. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor gas streams at locations that accurately represent the total sulfur concentration in the gas streams being burned in all flares, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

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

D.7.7 Greenhouse Gases (GHGs)

To determine the compliance status with Condition D.7.1(g), the following equation shall be used to determine the CO_2e emissions from the Loading Flare:

$$E_{LDG} = F_{LDG} \times 60.36\ \frac{\text{tons}}{\text{MMCF}} + L_N \times 3.77\text{E-03}\ \frac{\text{tons}}{\text{kgal}} + L_D \times 2.06\text{E-04}\ \frac{\text{tons}}{\text{kgal}}$$

Where:

E_{FLA} = CO_2e emissions (ton/month) for the Loading Flare
F_{LDG} = Fuel gas usage in the Loading Flare (MMCF/month)

L_N = Monthly naphtha loadout (kgal/month)
L_D = Monthly diesel loadout (kgal/month)
kgal = 1,000 gallons

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

D.7.8 Flare Pilot Flame [40 CFR 64]

In order to assure compliance with Condition D.7.4, the Permittee shall monitor the presence of the Product Loading Flare pilot flame using a thermocouple, infrared monitor, visual observation or any other equivalent device to detect the presence of a flame when the Product Loading Rack is in operation.

D.7.9 Total Sulfur Continuous Analyzer Equipment Downtime

(a) Whenever a Total Sulfur Continuous Analyzer is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup Total Sulfur Continuous Analyzer is not online within twenty-four (24) hours of shutdown or malfunction of the primary Total Sulfur Continuous Analyzer, the Permittee shall comply with the following:

    (1) The Permittee shall measure and record Draeger tube sampling of the flare gas stream one time per hour until the primary Total Sulfur Continuous Analyzer or a backup Total Sulfur Continuous Analyzer is brought online.

(b) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time.

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

D.7.10 Record Keeping Requirements

(a) To document compliance with Condition D.7.1(c)(2), (d)(2) and (f)(2), the Permittee shall maintain records, such as calculations and plans, demonstrating that the Loading Flare was designed to comply with 40 CFR 60.18.

(b) To document the compliance status with Condition D.7.1(g), the Permittee shall maintain records in accordance with (1) through (5) below. Records maintained for (1) through (5) shall be taken monthly and shall be complete and sufficient to establish compliance with the emission limits established in Condition D.7.1(g).

    (1) Calendar dates covered in the compliance determination period.
    (2) Monthly fuel gas usage in the Loading Flare.
    (3) Monthly volume of naphtha loaded
    (4) Monthly volume of diesel loaded
    (5) Monthly records of the CO_2e emissions.

(c) To document the compliance status with Condition D.7.8, the Permittee shall maintain records of temperature or other parameters sufficient to demonstrate the presence of a pilot flame when the Product Loading Flare is in operation.

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

D.7.11 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(B)] [326 IAC 3-5]

(a) The Permittee shall record the output of the Total Sulfur Continuous Analyzer ppmvd and shall perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the Total Sulfur Continuous Analyzer occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(c) To document the compliance status with Condition D.7.9(a)(1) the Permittee shall maintain hourly records of the Draeger tube sampling of the flare gas. The Permittee shall include in its record when the readings are not taken and the reason for the lack of the readings (e.g., the process did not operate that day).

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

D.7.12 Reporting Requirements

A quarterly report of CO_2e emissions and a quarterly summary of the information to document the compliance status with Condition D.7.1(g) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official," as defined by 326 IAC 2-7-1(35).

D.7.13 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) The Permittee shall prepare and submit to IDEM, OAQ a written report of the results of the calibration gas audits and relative accuracy test audits for each calendar quarter within thirty (30) calendar days after the end of each quarter. The report must contain the information required by 326 IAC 3-5-5(f).

(b) Pursuant to 326 IAC 3-5-7(5), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;
(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

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

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS - Residue

Emissions Unit Description:

(g) Residue solidification operations, identified as Block 5000, as follows:

(1) Four (4) pastillators, identified as EU-5001A - EU5001D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, using no emissions controls and exhausting to stack EU-5001.

(2) Four (4) pastillators, identified as EU-5002A - EU5002D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, using no emissions controls and exhausting to stack EU-5002.

(3) Four (4) pastillators, identified as EU-5003A - EU5003D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, using no emissions controls and exhausting to stack EU-5003.

(4) Four (4) pastillators, identified as EU-5004A - EU5004D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, using no emissions controls and exhausting to stack EU-5004.

(5) Enclosed conveyors for residue pellets, with particulate emissions controlled by filters EU-5009, EU-5010, and EU-5011, as follows:

(A) One (1) enclosed conveyor, identified as Block 1 & 2 transfer conveyors, with a maximum capacity of 34.33 tons per hour, receiving pastillators from the eight (8) pastillators, identified as EU-5001A - EU5001D and EU-5002A - EU5002D.

(B) One (1) enclosed conveyor, identified as Block 3 & 4 transfer conveyors, with a maximum capacity of 34.33 tons per hour, receiving pastillators from the eight (8) pastillators, identified as EU-5003A - EU5003D and EU-5004A - EU5004D.

(C) One (1) enclosed loading conveyor, identified as Loading Conveyor, approved in 2018 for construction, with a maximum capacity of 51.49 tons per hour, receiving pastillators from Block 1 & 2 and Block 3 & 4 transfer conveyors, and discharging to the bulk container loading station, railcar residue silo, or swing residue silo.

(6) One (1) residue bulk container loading station, identified as EU-5009, approved in 2018 for construction, with a maximum capacity of 8.00 tons per hour, using filter EU-5009 for particulate control and exhausting to stack EU-5009.

(7) One (1) railcar residue storage silo, identified as EU-5010, approved in 2018 for construction, with a maximum capacity of 1,236 tons per day, using baghouse EU-5010 for particulate control and exhausting to stack EU-5010.

(8) Two (2) residue loading hoppers, identified as EU-5005 and EU-5006, approved in 2018 for construction, with a combined maximum capacity of 1,236 tons per day, receiving residue from the railcar residue storage silo, using baghouse EU-5010 for particulate control and exhausting to stack EU-5010.

(9) One (1) swing residue storage silo, identified as EU-5011, approved in 2018 for construction, with a maximum capacity of 1,236 tons per day, using baghouse EU-5011 for particulate control and exhausting to stack EU-5011.

(10) Two (2) residue loading hoppers, identified as EU-5007 and EU-5008, approved in 2018 for construction, with a combined maximum capacity of 1,236 tons per day, receiving residue from the swing residue storage silo, using baghouse EU-5011 for particulate control and exhausting to stack EU-5011.

(11) Residue loadout operations using spouts and choke- flow-practices:

- (A) Two (2) railcar loadspots, approved in 2018 for construction.
- (B) Two (2) swing loadspots, approved in 2018 for construction, accommodating either trucks or railcars.

(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.8.1 Prevention of Significant Deterioration (PSD) BACT [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (Control Technology Review; Requirements), the Permittee shall comply with the following:

(a) VOC emissions from residue solidification unit EU-5001a-5001d (stack EU-5001) shall not exceed 1.40 lb/hr.

(b) VOC emissions from residue solidification unit EU-5002a-5002d (stack EU-5002) shall not exceed 1.40 lb/hr.

(c) VOC emissions from residue solidification unit EU-5003a-5003d (stack EU-5003) shall not exceed 1.40 lb/hr.

(d) VOC emissions from residue solidification unit EU-5004a-5004d (stack EU-5004) shall not exceed 1.40 lb/hr.

(e) PM, PM_{10}, and $PM_{2.5}$ for the solid residue handling operations shall be as follows:

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	gr/dscf	lb/hr
Residue bulk container loading and residue transfer conveyors (EU-5009)	Filter EU-5009 (stack EU-5009)	PM	0.002	0.001
		PM_{10}	0.002	0.001
		$PM_{2.5}$	0.002	0.001
Residue rail storage silo (EU-5010), loading hoppers (EU-5005, EU-5006), and residue transfer conveyors	Filter EU-5010 (stack EU-5010)	PM	0.002	0.003
		PM_{10}	0.002	0.003
		$PM_{2.5}$	0.002	0.003

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	**gr/dscf**	**lb/hr**
Residue swing storage silo (EU-5011), loading hoppers (EU-5007, EU-5008), and residue transfer conveyors	Filter EU-5011 (stack EU-5011)	PM	0.002	0.003
		PM_{10}	0.002	0.003
		$PM_{2.5}$	0.002	0.003

PM_{10} and $PM_{2.5}$ include both filterable and condensable PM.

(f) Transfers from the loading hoppers to transports shall employ choke flow-practices

(g) There shall be no visible emissions from transfers from the loading hoppers and from hoppers to transports.

D.8.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.8.3 Particulate Control

(a) In order to assure compliance with Condition D.8.1(e), the following control devices for particulate control shall be in operation and control particulate emissions from the associated emission units at all times those emission units are in operation:

Emission Unit Description	Unit ID	Control Device ID
Residue container loading and residue transfer conveyors	EU-5009	Filter EU-5009
Residue rail storage silo, loading hoppers, and residue transfer conveyors	EU-5005, EU-5006, EU-5010	Filter EU-5010
Residue swing storage silo, loading hoppers, and residue transfer conveyors	EU-5007, EU-5008, EU-5011	Filter EU-5011

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

D.8.4 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.8.1(a), not later than 180 days after the startup of EU-5001a-5001d (stack EU-5001) the Permittee shall perform VOC testing of EU-5001a-5001d (stack S-5001), utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration.

(b) In order to demonstrate compliance with Condition D.8.1(b), not later than 180 days after the startup of EU-5002a-5002d (stack EU-5002) the Permittee shall perform VOC testing of EU-5002a-5002d (stack S-5002), utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration.

(c) In order to demonstrate compliance with Condition D.8.1(c), not later than 180 days after the startup of EU-5003a-5003d (stack EU-5003) the Permittee shall perform VOC testing of EU-5003a-5003d (stack S-5003), utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration.

(d) In order to demonstrate compliance with Condition D.8.1(d), not later than 180 days after the startup of EU-5004a-5004d (stack EU-5004) the Permittee shall perform VOC testing of EU-5004a-5004d (stack S-5004), utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration.

(e) In order to demonstrate compliance with Condition D.8.1(e), not later than 180 days after the startup of Residue Container Loading (EU-5009) the Permittee shall perform PM, PM_{10}, and $PM_{2.5}$ testing of EU-5009 (stack EU-5009), utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration.

(f) In order to demonstrate compliance with Condition D.8.1(e), not later than 180 days after the startup of Residue Rail Storage Silo (EU-5010) the Permittee shall perform PM, PM_{10}, and $PM_{2.5}$ testing of EU-5010 (stack EU-5010), utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration.

(g) In order to demonstrate compliance with Condition D.8.1(e), not later than 180 days after the startup of Residue Swing Storage Silo (EU-5011) the Permittee shall perform PM, PM_{10}, and $PM_{2.5}$ testing of EU-5011 (stack EU-5011), utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration.

(h) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee’s obligation with regard to the performance testing required by this condition.

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

D.8.5 Parametric Monitoring

The Permittee shall record the pressure drop across the filters listed in the table below at least once per day when the associated emissions unit is in operation. When, for any one reading, the pressure drop across a filter is outside the normal range, the Permittee shall take a reasonable response. The normal range for this unit is a pressure drop between 3.0 and 6.0 inches of water unless a different upper-bound or lower-bound value for this range is determined during the latest stack test. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

Control Device ID
Filter EU-5009
Filter EU-5010
Filter EU-5011

The instruments used for determining the pressure shall comply with Section C – Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months.

D.8.6 Broken or Failed Bag Detection

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

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

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

D.8.7 Visible Emissions Notations

(a) Visible emission notations of residue loading operations shall be performed once per day during normal daylight operations. 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 a reasonable response. Section C – Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

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

D.8.8 Record Keeping Requirement

(a) To document the compliance status with Condition D.8.5, the Permittee shall maintain daily records of pressure drop across the filters. The Permittee shall include in its daily record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading (e.g. the process did not operate that day).

(b) To document the compliance status with Condition D.8.7, the Permittee shall maintain records of daily visible emission notations of the residue loading operations. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).

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

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS - Utilities

Emissions Unit Description:

(h) Utilities operations, identified as Block 6000, consisting of:

(2) One (1) three-cell crossflow mechanical draft cooling tower, identified as EU-6001, approved in 2018 for construction, with a maximum capacity of 32,000 gallons per hour, using mist eliminators and exhausting to stacks EU-6001, EU-6002, and EU-6003.

(3) One (1) diesel engine-driven emergency generator, identified as EU-6006, approved in 2018 for construction, with a maximum heat input capacity of 19.60 MMBtu/hr (2,800 hp) (average heating value), using no add-on controls and exhausting to stack EU-6006.

Under the NSPS, 40 CFR 60, Subpart IIII, emergency generator EU-6006 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart ZZZZ, emergency generator EU-6006 is an affected source.

(4) One (1) diesel engine-driven emergency fire pump, identified as EU-6008, approved in 2018 for construction, with a maximum heat input capacity of 5.25 MMBtu/hr (750 hp) (average heating value), using no add-on controls and exhausting to stack EU-6008.

Under the NSPS, 40 CFR 60, Subpart IIII, emergency fire pump EU-6008 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart ZZZZ, emergency fire pump EU-6008 is an affected source.

(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.9.1 Prevention of Significant Deterioration (PSD) Best Available Control Technology BACT)[326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (Control Technology Review; Requirements) , the Permittee shall comply with the following:

(a) PM, PM_{10}, and $PM_{2.5}$ emissions from the cooling tower (EU-6001, EU-6002 and EU-6003) shall be controlled by the use of drift eliminators with a maximum drift rate of no more than 0.0005%.

(b) Total dissolved solids (TDS) in the circulating cooling water shall not exceed 2,395 mg/l.

(c) VOC emissions from the cooling tower (EU-6001, EU-6002 and EU-6003) shall not exceed 1.34 lb/hr.

(d) Emissions from the emergency engines shall not exceed the following:

Emission Unit	Unit ID	Pollutant	Limitation	
Emergency Diesel Generator	EU-6006	PM	0.20 g/kW-hr	Use of Tier 2 diesel engine
		PM_{10}	0.20 g/kW-hr	
		$PM_{2.5}$	0.20 g/kW-hr	
		SO_2	15 ppm in fuel	
		NOx + NMHC	6.40 g/kW-hr	
		CO	3.50 g/kW-hr	
		Opacity	Acceleration: 20% Lugging: 15% Peak: 50%	
		CO_2e	811 tons per twelve (12) consecutive month period with compliance determined at the end of each month	
Emergency Diesel Fire Pump	EU-6008	PM	0.20 g/kW-hr	Engine that complies with Table 4, 40 CFR 60, Subpart IIII
		PM_{10}	0.20 g/kW-hr	
		$PM_{2.5}$	0.20 g/kW-hr	
		SO_2	15 ppm in fuel	
		NOx + NMHC	4.00 g/kW-hr	
		CO	3.50 g/kW-hr	
		CO_2e	217 tons per twelve (12) consecutive month period with compliance determined at the end of each month	

(e) Emergency generator (EU-6006) and emergency fire pump (EU-6008) shall use good combustion practices and shall use energy efficiency.

D.9.2 Air Quality Impact Requirements SO2 [326 IAC 2-2-5]

Pursuant to 326 IAC 2-2-5 (Air Quality Impact; Requirements), the source shall comply with the following:

(a) Emergency generator (EU-6006) shall not exceed 100 hours of operation per twelve (12) consecutive month period with compliance determined at the end of each month.

(b) Emergency fire pump (EU-6008) shall not exceed 200 hours of operation per twelve (12) consecutive month period with compliance determined at the end of each month.

D.9.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.9.4 Particulate Control

In order to assure compliance with Condition D.9.1(a), the drift eliminators for particulate control shall be in operation and control emissions from the cooling tower at all times the cooling tower is in operation.

D.9.5 Greenhouse Gases (GHGs)

To determine the compliance status with Condition D.9.1(d), the following equation shall be used to determine the CO_2e emissions from the Emergency Generator (EU-6006) and Emergency Fire Pump (EU-6008):

(a)

$$E_{6006} = H_{6006} \times 1.62\ \frac{\text{tons}}{\text{hr}}$$

Where:

E_{6006} = CO_2e emissions for operation of the Emergency Generator (EU-6006) (ton/month)
H_{6008} = Monthly hours of operation of the Emergency Generator (EU-6006), (hr/month)

(b)

$$E_{6008} = H_{6008} \times 0.43\ \frac{\text{tons}}{\text{hr}}$$

Where:

E_{6008} = CO_2e emissions for operation of the Emergency Fire Pump (EU-6008), (ton/month)
H_{6008} = Monthly hours of operation of the Emergency Fire Pump (EU-6008), (hr/month)

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

D.9.6 Compliance Monitoring Requirements

(a) To monitor compliance with Condition D.9.1(b), the Permittee shall take weekly measurements of the total dissolved solids (TDS) in the circulating water of the cooling tower. If the TDS limitation is exceeded, the Permittee shall perform shall take a reasonable response. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

(b) To monitor compliance with Condition D.9.1(c), the Permittee shall visually inspect the return water to the Cooling Tower (EU-6001, EU-6002, and EU-6003) for liquid VOC, including but not limited to the presence of a sheen, at least once per week. If VOC is observed, the Permittee shall take a reasonable response. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

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

D.9.6 Record Keeping Requirements

(a) To document the compliance status with Condition D.9.1(a), the Permittee shall maintain records documenting that the cooling tower mist eliminators have been certified to achieve the required drift rate.

(b) To document the compliance status with Condition D.9.1(b), the Permittee shall maintain records of the total dissolved solids (TDS) in the circulating water in the cooling tower and any remedial actions taken (including the date remedial actions were initiated).

(c) To document the compliance status with Condition D.9.1(c), the Permittee shall maintain records of the weekly visual inspection of cooling tower return water and any remedial actions taken (including the date remedial actions were initiated).

(d) To document the compliance status with Condition D.9.1(d) and 9.2, the Permittee shall maintain records in accordance with (1) through (4) below. Records maintained for (1) through (4) shall be taken monthly and shall be complete and sufficient to establish compliance with the emission limits established in Condition D.9.1(d) and 9.2.

(1) Calendar dates covered in the compliance determination period.
(2) Monthly hours of operation of the Emergency Generator (EU-6006).
(3) Monthly hours of operation of the Emergency Fire Pump (EU-6008).
(4) Monthly records of the CO_2e emissions.

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

D.9.7 Reporting Requirements

(a) A quarterly report of CO_2e emissions and a quarterly summary of the information to document the compliance status with Condition D.9.1(d) shall be submitted not later than thirty (30) days after the end of the quarter being reported.

(b) A quarterly report of hours of operation for EU-6006 and a quarterly summary of the information to document the compliance status with Condition D.9.2(a) shall be submitted not later than thirty (30) days after the end of the quarter being reported.

(c) A quarterly report of hours of operation for EU-6008 and a quarterly summary of the information to document the compliance status with Condition D.9.2(b) shall be submitted not later than thirty (30) days after the end of the quarter being reported.

(d) Section C - General Reporting Requirements contains the Permittee’s obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1(35).

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS - Hydrogen Plant

Emissions Unit Description:

(j) Hydrogen unit operations, identified as Block 7000, as follows:

(1) Hydrogen Plant 1, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7003, identified as Feed Water Treatment System 1, approved in 2018 for construction, using no controls and exhausting to stack EU-7003.

(B) One (1) feed preparation train, identified as Feed Prep 1, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7001, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7001, is an affected facility.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 1, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 1, approved in 2018 for construction, using no controls and discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 1 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 1 is an affected source.

(2) Hydrogen Plant 2, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7004, identified as Feed Water Treatment System 2, approved in 2018 for construction, using no controls and exhausting to stack EU-7004.

(B) One (1) feed preparation train, identified as Feed Prep 2, approved in 2018 for construction, consisting of

  (i) One (1) hydrogenation reactor.
  (ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

  (i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7002, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

  Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7003, is an affected facility.

  (ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 2, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 2, approved in 2018 for construction, using no controls and discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 2 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 2 is an affected source.

(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.10.1 Prevention of Significant Deterioration (PSD) BACT - Reformers [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (Control Technology Review; Requirements), the Permittee shall comply with the following requirements for the hydrogen production units identified as Hydrogen Plant 1 and Hydrogen Plant 2:

(a) The units shall burn only natural gas and process off-gas.

(b) PM, PM_{10}, and $PM_{2.5}$ emissions from each reformer shall not exceed:

Emission Limitations[1]	
Pollutant	**lb/MMBtu**
PM	0.006
PM_{10}*	0.006

Emission Limitations[1]	
Pollutant	**lb/MMBtu**
$PM_{2.5}$*	0.0048

1. PM_{10} and $PM_{2.5}$ shall include filterable and condensable PM.

(c) Sulfur content of the fuel gas delivered to each reformer shall not exceed 0.005 gr/scf.

(d) The units shall use selective catalytic reduction (SCR) with low-NOx burners for NOx control.

(e) NOx emissions from each reformer shall not exceed:

Emission Limitations	
Pollutant	**lb/MMBtu**
NOx	0.0065

(f) VOC emissions from each reformer shall not exceed:

Emission Limitations	
Pollutant	**lb/MMBtu[1]**
VOC	0.0015

(g) CO emissions from each reformer shall not exceed:

Emission Limitations	
Pollutant	**lb/MMBtu**
CO	0.020

(h) The CO_2e emissions from Block 7000 hydrogen production operations shall not exceed the values shown in the table below per twelve (12) consecutive month period, with compliance determined at the end of each month.

Emission Limitations	
Unit ID	**CO_2e Limit (tons)**
EU-7001	986,271
EU-7002	986,271
EU-7003	1,080
EU-7004	1,080

D.10.2 Prevention of Significant Deterioration (PSD) BACT - DA Vents [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (Control Technology Review; Requirements), the Permittee shall comply with the following requirements for the deaeration vents, identified as EU-7003 and EU-7004:

(a) VOC emissions from the hydrogen plant deaerators (EU-7003 and EU-7004) shall not exceed 3.20 lb/hr, each.

(b) CO emissions from the hydrogen plant deaerators (EU-7003 and EU-7004) shall not exceed 1.06 lb/hr, each.

D.10.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.10.4 Nitrogen Oxides (NOx) Control

In order to assure compliance with Condition D.10.1(d) and (e), the selective catalytic reduction (SCR) systems for NOx control shall be in operation and control emissions from the hydrogen plant reformers (EU-7001 and/or EU-7002) facility at all times the EU-7001 and/or EU-7002 facility are in operation.

D.10.5 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.10.1(b), (e), (f), and (g), not later than 180 days after the startup of hydrogen plant 1 reformer (EU-7001), the Permittee shall perform PM, PM_{10}, $PM_{2.5}$, VOC, and CO testing of the hydrogen plant 1 reformer (EU-7001) utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures).

(b) In order to demonstrate compliance with Condition D.10.1(b), (e), (f), and (g), not later than 180 days after the startup of hydrogen plant 2 reformer (EU-7002), the Permittee shall perform PM, PM_{10}, $PM_{2.5}$, VOC, and CO testing of the hydrogen plant 2 reformer (EU-7002) utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures).

(c) In order to demonstrate compliance with Condition D.10.2(a) and (b), not later than 180 days after the startup of hydrogen plant 1 deaeration vent (EU-7003), the Permittee shall perform VOC and CO testing of the hydrogen plant 1 deaeration vent (EU-7003) utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures).

(d) In order to demonstrate compliance with Condition D.10.2(a) and (b), not later than 180 days after the startup of hydrogen plant 2 deaeration vent (EU-7004), the Permittee shall perform VOC and CO testing of the hydrogen plant 2 deaeration vent (EU-7005) utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures).

(e) Section C – Performance Testing contains the Permittee’s obligation with regard to the performance testing required by this condition. PM10 and PM2.5 includes filterable and condensable PM.

D.10.6 Greenhouse Gases (GHGs)

To determine the compliance status with Condition D.10.1(h), the following equation shall be used to determine the CO_2e emissions from hydrogen production operations:

(a)

$$E_{HYi} = H_{HYi} \text{ x } 112.59 \text{ (tons } CO_2e\text{/hr)}$$

Where:

E_{HYi} = CO_2e emissions for hydrogen plant *i*, (ton/month)
H_{HYi} = Monthly hours of operation of hydrogen plant *i*, (hr/month)
i = indicator for hydrogen plant 1 or 2

(b)

$$E_{DAi} = H_{DAi} \text{ x } 0.12 \text{ (tons } CO_2e\text{/hr)}$$

Where:

E_{DAi} = CO_2e emissions for DA vent *i*, (ton/month)
H_{DAi} = Monthly hours of operation of DA vent, *i* (hr/month)
i = indicator for hydrogen plant 1 or 2

D.10.7 Continuous Emissions Monitoring [326 IAC 3-5] [326 IAC 2-7-6(1),(6)]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for EU-7001 and EU-7002 shall be calibrated, maintained, and operated for measuring NOx*,* and either CO_2 or O_2, which meet all applicable performance specifications of 326 IAC 3-5-2.

(b) In order to demonstrate compliance with Condition D.10.1(c), the Permittee shall install Total Sulfur Continuous Analyzers on the fuel gas to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in the reformers. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor fuel gas locations that accurately represent the total sulfur concentration in the fuel gas being burned in all heaters and boilers, other than fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(c) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5.

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

D.10.8 NOx Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a NOx continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NOx continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx CEMS, the Permittee shall comply with the following:

(1) Monitoring of the SCR operating parameters for ammonia flow rate and inlet duct temperature, shall be implemented. The parameters are as follows:

(A) The Permittee shall record the ammonia flow rate and inlet duct temperature at least four (4) times per hour until the primary CEM or a backup CEM is brought online and functioning properly. The Preventive Maintenance Plan for the SCR shall contain troubleshooting contingency and corrective actions for when the readings are outside of the normal range for any one reading during downtime of the NOx CEMS. When for any one reading, the ammonia flow rate and inlet duct temperature are outside the normal range during downtime of the NOx CEMS, the Permittee shall take reasonable response steps. Section C – Response to Excursions or Exceedances contains the Permittee's obligation with regard to the response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

(B) The instrument used for determining the ammonia flow rate and inlet duct temperature shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months.

(c) Whenever a Total Sulfur Continuous Analyzer is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup Total Sulfur Continuous Analyzer is not online within twenty-four (24) hours of shutdown or malfunction of the primary Total Sulfur Continuous Analyzer, the Permittee shall comply with the following:

(1) The Permittee shall measure and record Draeger tube sampling of the fuel gas one time per hour until the primary Total Sulfur Continuous Analyzer or a backup Total Sulfur Continuous Analyzer is brought online.

(d) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time.

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

D.10.9 Record Keeping Requirement

(a) To document the compliance status with Condition D.10.1(h), the Permittee shall maintain records in accordance with (1) through (3) below. Records maintained for (1) through (3) shall be taken monthly and shall be complete and sufficient to establish compliance with the emission limits established in Condition D.10.1(h).

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

(2) Monthly hours of operation for hydrogen plants 1 and 2 and deaeration vents 1 and 2.
(3) Monthly records of the CO_2e emissions.

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

D.10.10 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(A)(iii)][326 IAC 3-5]

(a) The Permittee shall record the output of the NOx continuous monitoring system(s) in pounds per hour and shall perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the NOx continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(c) To document the compliance status with Condition D.10.8(b)(1) the Permittee shall maintain four time per hour records of the ammonia flow rate and inlet duct temperature. The Permittee shall include in its record when the readings are not taken and the reason for the lack of the readings (e.g., the process did not operate that day).

(d) The Permittee shall record the output of the Total Sulfur Continuous Analyzers in grain per standard cubic foot on an hourly average, monthly average and twelve (12) month average.

(e) To document the compliance status with Condition D.10.8(c)(1) the Permittee shall maintain hourly records of the Draeger tube sampling of the fuel gas. The Permittee shall include in its record when the readings are not taken and the reason for the lack of the readings (e.g., the process did not operate that day).

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

D.10.11 Reporting Requirements

(a) A quarterly report of CO_2e emissions and a quarterly summary of the information to document the compliance status with Condition D.10.1(h) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting Requirements contains the Permittee’s obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1(35).

D.10.12 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(A)(iii)][326 IAC 3-5]

(b) Pursuant to 326 IAC 3-5-7(5), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;
(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1 (35).

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS - Water

Emissions Unit Description:

(i) Water supply and treatment operations, identified as Block 6500, consisting of:

(1) One (1) pneumatic lime truck unloading system, identified as Lime Unloading, approved in 2018 for construction, with a maximum capacity of 20.00 tons per hour, discharging to silo EU-6501.

(2) One (1) lime storage silo, identified as EU-6501, approved in 2018 for construction, with a maximum capacity of 20.00 tons per hour, controlled by dust collector EU-6501 and exhausting to stack EU-6501.

(k) Wastewater treatment operations, identified as Block 8000, as follows:

(1) One (1) wastewater junction box with associated process drains, identified as Oily Water Sump, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8002.

(2) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Water Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and water to MH1.

(3) One (1) wastewater junction box with, identified as MH1, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stacl EU-8003.

(4) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Amine Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and amine solution to the Rich Amine Return Header.

(5) One (1) biological wastewater treatment system, approved in 2018 for construction, with emissions exhausting to vent EU-8001.

Under the NSPS, 40 CFR 60, Subpart QQQ, the process drains, junction boxes, Oily Water Separator, Oily Amine Separator, associated sewer lines, and any secondary oil-water separator in the biological wastewater treatment system are an affected aggregate facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Oily Water Separator, Oily Amine Separator, and any secondary oil-water separator in the biological wastewater treatment system are affected sources.

Under the NESHAP, 40 CFR 63, Subpart CC, the wastewater streams and treatment operations associated with petroleum refining process units are part of a new affected source..

(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.11.1 Prevention of Significant Deterioration (PSD) BACT [326 IAC 2-2-3] [326 IAC 8-1-6]

(a) Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the lime handling operations shall be as follows:

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	**gr/dscf**	**lb/hr**
Lime silo (EU-6501)	Filter EU-6501 (stack EU-6501)	PM	0.002	0.01
		PM_{10}	0.002	0.01
		$PM_{2.5}$	0.002	0.01

PM_{10} and $PM_{2.5}$ include both filterable and condensable.

(b) Pursuant to 326 IAC 2-2-3 (Control Technology Review; Requirements) and 326 IAC 8-1-6 (New Facilites; General Reduction Requirements), VOC emissions from the wastewater treatment vent (EU-8001), oily water sump (EU-8002), and manhole no. 1 (EU-8003) shall not exceed 20 parts per million by volume (dry) (ppmvd), each.

D.11.2 Wastewater Separators [326 IAC 8-4-2(2)]

The Permittee shall equip all separators, forebay, and openings in covers with lids or seals such that the lids or seals are in the closed position at all times except when in actual use.

D.11.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

D.11.4 Particulate Control

(a) In order to assure compliance with Condition D.11.1, the following control devices for particulate control shall be in operation and control particulate emissions from the associated emission units at all times those emission units are in operation:

Emission Unit Description	Unit ID	Control Device ID
Lime unloading	EU-6501	Filter EU-6501

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

D.11.5 VOC Control

(a) In order to assure compliance with Condition D.11.1(b), the carbon canister for VOC control shall be in operation and control emissions from the Oily Water Sump facility at all times the Oily Water Sump facility is in operation.

(b) In order to assure compliance with Condition D.11.1(b), the carbon canister for VOC control shall be in operation and control emissions from the Manhole No. 1 facility at all times the Manhole No. 1 facility is in operation.

D.11.6 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.11.1(a), not later than 180 days after the startup of Lime Unloading System (EU-6501) the Permittee shall perform PM, PM_{10}, and $PM_{2.5}$ testing of EU-6501 (stack EU-6501), utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration.

(b) In order to demonstrate compliance with Condition D.11.1(b), not later than 180 days after the startup of the wastewater treatment system the Permittee shall perform VOC testing of the wastewater treatment system vent (stack EU-8001), utilizing methods approved by the commissioner at least once every five years from the date of the most recent valid compliance demonstration.

(c) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

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

D.11.7 Filter Inspection

The Permittee shall perform semi-annual inspections of the filters listed in the table below controlling particulate emissions from the lime handling processes to verify that they are being operated and maintained in accordance with the manufacturer's specifications. Inspections required by this condition shall not be performed in consecutive months. All defective bags or filters shall be replaced.

Control Device ID
Filter EU-6501

D.11.8 Broken or Failed Bag Detection

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

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

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

D.11.9 Carbon Canister Monitoring

In order to demonstrate compliance with Condition D.11.1(b), the Permittee shall monitor either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from each carbon canister on a regular schedule, and the existing carbon canister shall be replaced with a fresh canister 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 either the organic concentration or the benzene concentration in the gas stream vented to the carbon canister.

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

D.11.10 Record Keeping Requirement

(a) To document the compliance status with Condition D.11.7, the Permittee shall maintain records of the dates and results of the inspections.

(b) To document the compliance status with Condition D.11.9, the Permittee shall maintain daily records of the VOC or benzene content for each carbon canister exhaust vent. The Permittee shall include in its daily record when the readings are not taken and the reason for the lack of the readings (e.g., the process did not operate that day).

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

SECTION D.12 EMISSIONS UNIT OPERATION CONDITIONS - Refinery

Emissions Unit Description:

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(5) One (1) nitrogen-blanketed Na_2S slurry preparation system, identified as Na_2S Slurry Preparation, approved in 2018 for construction, with a maximum capacity of 0.077 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Na_2S Handling System Filter, exhausting to stack EU-2008, consisting of:

(C) One (1) nitrogen-blanketed mixing drum for Na_2S and Block 2000 vacuum tower VGO (vacuum gas oil) discharging to the feed premix drum.

Under the NSPS, 40 CFR 60, Subpart GGGa, the mixing drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the mixing drum is an affected source.

(6) One (1) feed premix drum, identified as Feed Premix Drum, approved in 2018 for construction, receiving coal, solid additives, and recycled vacuum gas oil (VGO) and discharging to the feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed premix drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed premix drum is an affected source.

(7) One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2018 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

Under the NSPS, 40 CFR 60, Subpart Ja, the feed heater EU-2001 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed heater EU-2001 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed heater EU-2001 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, feed heater EU-2001 is an affected source.

(8) One (1) natural gas and process fuel gas-fired indirect treat gas heater, identified as EU-2002, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 52.8 MMBtu/hr (HHV), receiving hydrogen from Block 7000 and discharging to the 1st stage reactors, exhausting to stack EU-2002.

Under the NSPS, 40 CFR 60, Subpart Ja, the treat gas heater EU-2002 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, treat gas heater EU-2002 is an affected source.

(9) One (1) first stage reactor - liquid phase hydrocracking system, identified as LPH, approved in 2018 for construction, discharging to the hot separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the first stage reactor - liquid phase hydrocracking system is an affected source.

(10) One (1) hot separator, identified as Hot Separator, approved in 2018 for construction, discharging vapor to the 2nd stage reactors and liquids to the vacuum column feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the hot separator is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the hot separator is an affected source.

(11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the vacuum distillation tower, exhausting to stack EU-2003.

Under the NSPS, 40 CFR 60, Subpart Ja, the vacuum column feed heater EU-2003 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum column feed heater EU-2003 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum column feed heater EU-2003 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, vacuum column feed heater EU-2003 is an affected source.

(12) One (1) vacuum distillation tower, identified as Vacuum Distillation Column, approved in 2018 for construction, discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 4000, phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum distillation tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the vacuum distillation tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum distillation tower is an affected source.

(13) One (1) second stage reactor - gas phase hydrotreating system, identified as GPH, approved in 2018 for construction, discharging to the cold separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the second stage reactor - gas phase hydrotreating system is an affected source.

(14) One (1) cold separator , identified as Cold Separator, approved in 2018 for construction, discharging non-phenolic sour water to Block 3000 and hydrocarbons to the fractionator heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the cold separator is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the cold separator is an affected source.

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

Under the NSPS, 40 CFR 60, Subpart Db, fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, the fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator heater is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator heater is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, fractionator heater EU-2004 is an affected source.

(16) One (1) fractionator tower, identified as Fractionator Tower, approved in 2018 for construction, discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix Drum, and non-phenolic sour water to Block 3000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the fractionator tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator tower is an affected source.

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

(A) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the HP Absorber and LP Absorber are affected sources.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the HP Absorber and LP Absorber is an affected source.

(f) Offsites operations, identified as Block 4000, consisting of:

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T1	IFR	Naphtha product	4,629,879 (17,524)	-
T2	IFR	Naphtha product	4,629,879 (17,524)	-
T3	FR	Diesel product	4,525,796 (17,130)	-
T4	FR	Diesel product	4,525,796 (17,130)	-
T5	FR	Diesel product	4,525,796 (17,130)	-
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)	-

T13	FR	VGO tank 1	926,980 (3,509)	-
T14	FR	VGO tank 2	926,980 (3,509)	-
T16	FR	Slop tank	4,195,581 (15,880)	LP flare

1. *FR - fixed roof, IFR - internal floating roof, HPV-horizontal pressure vessel*
2. *Tank vents to flares are part of sweep and pilot gas streams.*

Under the NSPS, 40 CFR 60, Subpart Kb, T1, T2, and T6 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, T1 - T6 and T10 - T15 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart QQQ, T16 is part of an affected facility.

Under the NSPS, 40 CFR 61, Subpart FF, T16 and T18 - T21 are part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, T1 - T6, T10 - T14, T16, and T18-T23 are part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart WW, T3 - T6 and T10 - T14 are affected sources.

(3) Loading operations, as follows:

(A) One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Product Loading Rack is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart BB, the Product Loading Rack is an affected source.

Under the NESHAP, 40 CFR 63, Subpart CC, the Product Loading Rack is an affected source.

Insignificant Activities

(l) An emission unit or activity whose potential uncontrolled emissions meet the exemption levels specified in 326 IAC 2-1.1-3(e)(1) or the exemption levels specified in the following, whichever is lower:

- For lead or lead compounds measured as elemental lead, the exemption level is six-tenths (0.6) ton per year or three and twenty-nine hundredths (3.29) pounds per day.
- For carbon monoxide (CO), the exemption limit is twenty-five (25) pounds per day.
- For sulfur dioxide, the exemption level is five (5) pounds per hour or twenty-five (25) pounds per day.
- For VOC, the exemption limit is three (3) pounds per hour or fifteen (15) pounds per day.

- For nitrogen oxides (NOx), the exemption limit is five (5) pounds per hour or twenty-five (25) pounds per day.
- For PM10 or direct PM2.5, the exemption level is either five (5) pounds per hour or twenty-five (25) pounds per day.

As follows:

(1) Fugitive leaks of VOC and HAPs from equipment in VOC service, subject to NSPS or NESHAP, but individually less than the exemption levels listed above.

(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.12.1 Prevention of Significant Deterioration (PSD) BACT [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for VOC from refinery process fugitive emissions has been determined to be:

(a) Fugitive VOC emissions shall be controlled by a Leak Detection and Repair (LDAR) program. The leak detection and repair program specified in 40 CFR 60, Subpart GGGa shall serve as BACT for VOC fugitive emissions.

(1) Fugitive VOC emissions from Block 2000 VEBA Combi Cracker operations shall not exceed 151.18 tons per twelve (12) consecutive month period, with compliance determined monthly.

(2) Fugitive VOC emissions from Block 4000 offsites operations shall not exceed 25.04 tons per twelve (12) consecutive month period.

D.12.1 Petroleum Refineries [326 IAC 8-4-2]

(a) Pursuant to 326 IAC 8-4-2(1), the Permittee shall not cause, allow or permit the emission of any noncondensable volatile organic compounds from the condensers, hot wells or accumulators of any vacuum producing system.

(b) Pursuant to 326 IAC 8-4-2(3), the Permittee shall notify the commissioner thirty (30) days prior to a process unit turnaround. In addition, the Permittee shall minimize volatile organic compound emissions during turnaround, by providing for:

(1) Depressurization venting of the process unit or vessel to a vapor recovery system, flare or firebox; and

(2) No emission of volatile organic compounds from a process unit or vessel until its internal pressure is 136 kPa (19.7 psia) or less.

D.12.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS - Roads

Emissions Unit Description:

Insignificant Activities

(d) Paved roads and parking lots with public access.

(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.13.1 Prevention of Significant Deterioration (PSD) BACT [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 Control Technology Review; Requirements), the Permittee shall comply with the following:

(a) The Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the paved roads shall be the development, maintenance, and implementation of a fugitive dust control plan, which shall include but not be limited to vacuum sweeping and water flushing as necessary and the implementation of a speed reduction plan.

(b) Visible emissions from truck traffic on plant roads shall not exceed one (1) minute in any one (1) hour period.

D.13.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

SECTION E.1 NSPS

Emissions Unit Description:

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

Under the NSPS, 40 CFR 60, Subpart Db, fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, the fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator heater is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator heater is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, fractionator heater EU-2004 is an affected source.

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

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

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

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Db.

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

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

E.1.2 Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units NSPS [326 IAC 12][40 CFR Part 60, Subpart Db]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Db (included as Attachment B to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.40b(a)
(2) 40 CFR 60.40b(c)
(3) 40 CFR 60.40b(g)
(4) 40 CFR 60.40b(j)
(5) 40 CFR 60.41b
(6) 40 CFR 60.44b(a)(1)
(7) 40 CFR 63.44b(c)
(8) 40 CFR 63.44b(e)
(9) 40 CFR 60.44b(f)
(10) 40 CFR 60.44b(h)
(11) 40 CFR 60.44b(i)
(12) 40 CFR 60.46b(a)
(13) 40 CFR 60.46b(c)
(14) 40 CFR 60.46b(e)
(15) 40 CFR 60.48b(b)
(16) 40 CFR 60.48b(c)
(17) 40 CFR 60.48b(d)
(18) 40 CFR 60.48b(e)(2)
(19) 40 CFR 60.48b(f)
(20) 40 CFR 60.49b

SECTION E.2 NSPS

Emissions Unit Description:

(e) Sulfur recovery operations, identified as Block 3000, consisting of:

(3) Sulfur Recovery System, consisting of:

(A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605A Incinerator and A-605A Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit A is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit A is an affected source.

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605B Incinerator and A-605B Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit B is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit B is an affected source.

(h) Utilities operations, identified as Block 6000, consisting of:

(1) One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 68.50 MMBtu/hr (HHV), exhausting to stack EU-6000.

Under the NSPS, 40 CFR 60, Subpart Dc, boiler EU-6000 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, boiler EU-6000 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, boiler EU-6000 is an affected source.

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

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

E.2.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1][40 CFR Part 60, Subpart A]

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

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

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

E.2.2 Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units NSPS [326 IAC 12][40 CFR Part 60, Subpart Dc]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Dc (included as Attachment C to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.40c(a)
(2) 40 CFR 60.40c(b)
(3) 40 CFR 60.40c(h)
(4) 40 CFR 60.41c

(5) 40 CFR 60.48c

SECTION E.3 NSPS

Emissions Unit Description:

(b) Coal drying loop, collectively identified as EU-1008, with emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008, consisting of the following:

(3) One (1) natural gas and process fuel gas-fired heater, identified as Coal Dryer Heater EU-1007, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 55.8 MMBtu/hr (HHV), with emissions exhausting to Stack EU-1007.

Under the NSPS, 40 CFR 60, Subpart Ja, the Coal Dryer Heater (EU-1007) is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Heater (EU-1007) is part of an affected thermal dryer.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, the Coal Dryer Heater (EU-1007) is an affected source.

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(7) One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2018 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

Under the NSPS, 40 CFR 60, Subpart Ja, the feed heater EU-2001 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed heater EU-2001 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed heater EU-2001 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, feed heater EU-2001 is an affected source.

(8) One (1) natural gas and process fuel gas-fired indirect treat gas heater, identified as EU-2002, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 52.8 MMBtu/hr (HHV), receiving hydrogen from Block 7000 and discharging to the 1st stage reactors, exhausting to stack EU-2002.

Under the NSPS, 40 CFR 60, Subpart Ja, the treat gas heater EU-2002 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, treat gas heater EU-2002 is an affected source.

(11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the vacuum distillation tower, exhausting to stack EU-2003.

Under the NSPS, 40 CFR 60, Subpart Ja, the vacuum column feed heater EU-2003 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum column feed heater EU-2003 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum column feed heater EU-2003 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, vacuum column feed heater EU-2003 is an affected source.

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

Under the NSPS, 40 CFR 60, Subpart Db, fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, the fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator heater is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator heater is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, fractionator heater EU-2004 is an affected source.

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

(A) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the HP Absorber and LP Absorber are affected sources.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the HP Absorber and LP Absorber is an affected source.

(e) Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

(A) One (1) heat exchanger, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) stripper column , identified as Stripper, approved in 2018 for construction, discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger and the reboiler and vapor to the overheads condenser, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(C) One (1) water-cooled condenser, identified as Overheads Condenser, approved in 2018 for construction, discharging condensate to the stripper condenser accumulator, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(D) One (1) accumulator drum, identified as Stripper Condenser Accumulator, approved in 2018 for construction, discharging condensate to stripper reflux and the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(E) One (1) steam-heated reboiler, identified as Stripper Reboiler, approved in 2018 for construction, discharging lean amine to the stripper reflux, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Amine Recovery Unit is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Amine Recovery Unit part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Amine Recovery Unit is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Amine Recovery Unit is an affected source.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Sour Water Stripping System is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Sour Water Stripping System is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Sour Water Stripping System is an affected source.

(3) Sulfur Recovery System, consisting of:

(A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the TGTU A heat exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.

(x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605A Incinerator and A-605A Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit A is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit A is an affected source.

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.

(ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.

(iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.

(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.

(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.

(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.

(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.

(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.

(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.

(x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605B Incinerator and A-605B Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit B is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit B is an affected source.

(f) Offsites operations, identified as Block 4000, consisting of:

(1) Flares, as follows:

(A) One (1) natural gas and process fuel gas-fired flare identified as High Pressure (HP) Flare, approved in 2018 for construction, servicing overpressure and emergency reliefs from Block 2000 VEBA Combi Cracker operations, controlling emissions from Block 2000 depressurization system, with pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(B) One (1) natural gas and process fuel gas-fired flare, identified as Low Pressure (LP) Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 7000 Hydrogen Unit operations, controlling emissions Block 7000 start-up and shut-down vents, and a continuous sweep stream from the Block 2000 slop tank, with a sweep and pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(C) One (1) natural gas and process fuel gas-fired flare, identified as Sulfur Block Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 3000 Sulfur Recovery operations and sulfur loading, controlling emergency streams from Sulfur Recovery Units A and B, and a continuous sweep stream from the sour water storage tanks, with a sweep and pilot heat input capacity of 0.77 MMBtu/hr (LHV), exhausting to the atmosphere.

(D) One (1) natural gas and process fuel gas-fired flare, identified as Loading Flare, approved in 2018 for construction, servicing Block 4000 naphtha, diesel, and ammonia loading operations, with a pilot heat input capacity of 0.20 MMBtu/hr (LHV), exhausting to the atmosphere.

Under the NSPS, 40 CFR 60, Subpart Ja, the flares are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, the flares are affected facilities.

Under the NESHAP, 40 CFR 63, Subpart CC, the flares are affected sources.

(h) Utilities operations, identified as Block 6000, consisting of:

(1) One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 68.50 MMBtu/hr (HHV), exhausting to stack EU-6000.

Under the NSPS, 40 CFR 60, Subpart Dc, boiler EU-6000 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, boiler EU-6000 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, boiler EU-6000 is an affected source.

(j) Hydrogen unit operations, identified as Block 7000, as follows:

(1) Hydrogen Plant 1, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7001, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7001, is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 1 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 1 is an affected source.

(2) Hydrogen Plant 2, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7002, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7003, is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 2 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 2 is an affected source.

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

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

E.3.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Ja

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

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

E.3.2 Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 NSPS [326 IAC 12] [40 CFR Part 60, Subpart Ja]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Ja (included as Attachment D to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.100a
(2) 40 CFR 60.101a
(3) 40 CFR 60.102a(a)
(4) 40 CFR 60.102a(f)(1)
(5) 40 CFR 60.102a(g)
(6) 40 CFR 60.103a(a)
(7) 40 CFR 60.103a(b)
(8) 40 CFR 60.103a(c)
(9) 40 CFR 60.103a(d)
(10) 40 CFR 60.103a(e)
(11) 40 CFR 60.103a(h)
(12) 40 CFR 60.103a(j)
(13) 40 CFR 60.104a(a)
(14) 40 CFR 60.104a(c)
(15) 40 CFR 60.104a(h)
(16) 40 CFR 60.104a(i)
(17) 40 CFR 60.104a(j)
(18) 40 CFR 60.106a
(19) 40 CFR 60.107a(a)
(20) 40 CFR 60.107a(b)
(21) 40 CFR 60.107a(c)
(22) 40 CFR 60.107a(d)
(23) 40 CFR 60.107a(e)
(24) 40 CFR 60.107a(f)
(25) 40 CFR 60.107a(g)

(26) 40 CFR 60.107a(i)
(27) 40 CFR 60.108a
(28) 40 CFR 60.109a

SECTION E.4 **NSPS**

Emissions Unit Description:

(f) Offsites operations, identified as Block 4000, consisting of:

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T1	IFR	Naphtha product	4,629,879 (17,524)	-
T2	IFR	Naphtha product	4,629,879 (17,524)	-
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)	-

1. *FR - fixed roof, IFR - internal floating roof, HPV-horizontal pressure vessel*
2. *Tank vents to flares are part of sweep and pilot gas streams.*

Under the NSPS, 40 CFR 60, Subpart Kb, T1, T2, and T6 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, T1 - T6 and T10 - T15 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart QQQ, T16 is part of an affected facility.

Under the NSPS, 40 CFR 61, Subpart FF, T16 and T18 - T21 are part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, T1 - T6, T10 - T15, T16, and T18-T23 are part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart WW, T3 - T6 and T10 - T15 are affected sources.

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

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

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

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Kb.

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

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

E.4.2 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 NSPS [326 IAC 12][40 CFR Part 60, Subpart Kb]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Kb (included as Attachment E to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.110b(a)
(2) 40 CFR 60.110b(e)
(3) 40 CFR 60.111b
(4) 40 CFR 60.112b(a)(1)
(5) 40 CFR 60.113b(a)
(6) 40 CFR 60.114b
(7) 40 CFR 60.115b(a)
(8) 40 CFR 60.116b
(9) 40 CFR 60.117b

SECTION E.5 NSPS

Emissions Unit Description:

(a) Coal handling operations, identified as Block 1000, consisting of:

(1) One (1) shelter-type railcar dump unloading facility, identified as EU-1000, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1000, exhausting to stack EU-1000, consisting of:

(A) Two (2) enclosed receiving pits, identified as Receiving Pit 1 and Receiving Pit 2, discharging to Receiving Bin 1 and Receiving Bin 2, respectively.
(B) Two (2) enclosed receiving bins, identified as Receiving Bin 1 and Receiving Bin 2, discharging to Drag Flight Feeder 1 and Drag Flight Feeder 2, respectively, with water spray dust suppression systems.
(C) Two (2) enclosed drag flight feeders, identified as Drag Flight Feeder 1 and Drag Flight Feeder 2, discharging to the Unloading Conveyor, with water spray dust suppression systems.

Under the NSPS, 40 CFR 60, Subpart Y, EU-1000 is an affected facility.

(2) One (1) enclosed rail unloading conveyor discharging to Transfer Station 1, identified as Unloading Conveyor, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

Under the NSPS, 40 CFR 60, Subpart Y, the Unloading Conveyor is an affected facility.

(3) One (1) enclosed transfer station discharging to Conveyor 1, Conveyor 2, or Conveyor 9, identified as Transfer Station 1 (EU-1001), approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

Under the NSPS, 40 CFR 60, Subpart Y, Transfer Station 1 (EU-1001) is an affected facility.

(4) One (1) enclosed feed conveyor discharging to Stacker 1 Boom Conveyor/Chute, identified as Conveyor 1, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 1 is an affected facility.

(5) One (1) enclosed stacker boom conveyor/chute discharging to Coal Stockpiles #1A & #1B, identified as Stacker 1 Boom Conveyor/Chute, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Stacker 1 Conveyor/Chute is an affected facility.

(6) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #1A and Stockpile #1B, with a maximum capacity of 93,000 tons, controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Stockpiles #1A and #1B are affected facilities.

(7) One (1) enclosed feed conveyor discharging to Stacker 2 Boom Conveyor/Chute, identified as Conveyor 2, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 2 is an affected facility.

(8) One (1) enclosed stacker boom conveyor/chute discharging to Coal Stockpiles #2A & #2B, identified as Stacker 2 Boom Conveyor/Chute, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Stacker 2 Boom Conveyor/Chute is an affected facility.

(9) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #2A and Stockpile #2B, with a maximum capacity of 93,000 tons, controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Stockpiles #2A and #2B are affected facilities.

(10) One (1) reclaimer for Stockpiles #1A & #1B, discharging to Reclaim Conveyor 6, identified as Reclaimer 1, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Reclaimer 1 is an affected facility.

(11) One (1) enclosed reclaimer conveyor, identified as Conveyor 6 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 6 is an affected facility.

(12) One (1) reclaimer for Stockpiles #2A & #2B, discharging to Reclaim Conveyor 7, identified as Reclaimer 2, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Reclaimer 2 is an affected facility.

(13) One (1) enclosed reclaimer conveyor, identified as Conveyor 7 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 7 is an affected facility.

(14) One (1) enclosed transfer station conveyor, identified as Conveyor 9 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 9 is an affected facility.

(15) One (1) enclosed reclaim transfer station discharging to Reclaim Conveyor 8, identified as Reclaim Transfer Station (EU-1006), approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Reclaim Transfer Station is an affected facility.

(16) One (1) enclosed conveyor, identified as Reclaim Conveyor 8 discharging to the Coal Mill and Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with emissions controlled the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 8 is an affected facility.

(b) Coal drying loop, collectively identified as EU-1008, with emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU -1008, consisting of the following:

(1) One (1) enclosed coal mill and pulverizer, identified as Coal Mill and Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer, with particulate emissions controlled the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Mill and Pulverizer is an affected facility.

(2) One (1) enclosed coal dryer, identified as Coal Dryer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer Baghouse, with particulate emissions controlled by the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer is an affected facility.

(3) One (1) natural gas and process fuel gas-fired heater, identified as Coal Dryer Heater EU-1007, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 55.8 MMBtu/hr (HHV), with emissions exhausting to Stack EU-1007.

Under the NSPS, 40 CFR 60, Subpart Ja, the Coal Dryer Heater (EU-1007) is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Heater (EU-1007) is part of an affected thermal dryer.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, the Coal Dryer Heater (EU-1007) is an affected source.

(4) One (1) process baghouse, identified as Coal Dryer Baghouse, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging fines to the Block 2000 Coal Hopper, exhausting particulate and filtered nitrogen to the condenser.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Baghouse is an affected facility.

(5) One (1) water-cooled condenser, identified as Drying Loop Condenser, approved in 2018 for construction, with a nominal capacity of 40 MMBtu/hr, controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008.

Under the NSPS, 40 CFR 60, Subpart Y, the Drying Loop Condenser is part of an affected thermal dryer.

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(1) One (1) enclosed hopper receiving coal from Block 1000 Coal Dryer Baghouse and discharging to the Feed Prep Screw Conveyor, identified as Coal Hopper, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Hopper is an affected facility.

(2) One (1) enclosed screw conveyor, identified as Closed Screw Conveyor, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Feed Premix Drum, identified as Closed Screw Conveyor, with particulate emissions controlled by the Coal Handling System Filter, exhausting to stack EU-2005.

Under the NSPS, 40 CFR 60, Subpart Y, the Closed Screw Conveyor is an affected facility.

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

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

E.5.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1][40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Y.

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

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

E.5.2 Standards of Performance for Coal Preparation and Processing Plants NSPS [326 IAC 12][40 CFR Part 60, Subpart Y]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Y (included as Attachment F to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.250(a)
(2) 40 CFR 60.250(d)
(3) 40 CFR 60.251
(4) 40 CFR 60.252(b)(1)
(5) 40 CFR 60.252(b)(2)
(6) 40 CFR 60.252(b)(3)
(7) 40 CFR 60.252(c)
(8) 40 CFR 60.254(b)
(9) 40 CFR 60.255(b)
(10) 40 CFR 60.255(c)
(11) 40 CFR 60.255(d)
(12) 40 CFR 60.255(e)
(13) 40 CFR 60.255(f)
(14) 40 CFR 60.255(g)
(15) 40 CFR 60.256(b)
(16) 40 CFR 60.256(c)
(17) 40 CFR 60.257
(18) 40 CFR 60.258

SECTION E.6 **NSPS**

Emissions Unit Description:

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(5) One (1) nitrogen-blanketed Na_2S slurry preparation system, identified as Na_2S Slurry Preparation, approved in 2018 for construction, with a maximum capacity of 0.077 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Na_2S Handling System Filter, exhausting to stack EU-2008, consisting of:

(A) One (1) Na_2S silo rotary feeder solid weigh scale.
(B) One (1) Na_2S screw conveyor discharging to the Na_2S mixing drum.
(C) One (1) nitrogen-blanketed mixing drum for Na_2S and Block 2000 vacuum tower VGO (vacuum gas oil) discharging to the feed premix drum.

Under the NSPS, 40 CFR 60, Subpart GGGa, the mixing drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the mixing drum is an affected source.

(6) One (1) feed premix drum, identified as Feed Premix Drum, approved in 2018 for construction, receiving coal, solid additives, and recycled vacuum gas oil (VGO) and discharging to the feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed premix drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed premix drum is an affected source.

(7) One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2018 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

Under the NSPS, 40 CFR 60, Subpart Ja, the feed heater EU-2001 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed heater EU-2001 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed heater EU-2001 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, feed heater EU-2001 is an affected source.

(9) One (1) first stage reactor - liquid phase hydrocracking system, identified as LPH, approved in 2018 for construction, discharging to the hot separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the first stage reactor - liquid phase hydrocracking system is an affected source.

(10) One (1) hot separator, identified as Hot Separator, approved in 2018 for construction, discharging vapor to the 2nd stage reactors and liquids to the vacuum column feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the hot separator is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the hot separator is an affected source.

(11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the vacuum distillation tower, exhausting to stack EU-2003.

Under the NSPS, 40 CFR 60, Subpart Ja, the vacuum column feed heater EU-2003 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum column feed heater EU-2003 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum column feed heater EU-2003 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, vacuum column feed heater EU-2003 is an affected source.

(12) One (1) vacuum distillation tower, identified as Vacuum Distillation Column, approved in 2018 for construction, discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 4000, phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum distillation tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the vacuum distillation tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum distillation tower is an affected source.

(13) One (1) second stage reactor - gas phase hydrotreating system, identified as GPH, approved in 2018 for construction, discharging to the cold separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the second stage reactor - gas phase hydrotreating system is an affected source.

(14) One (1) cold separator , identified as Cold Separator, approved in 2018 for construction, discharging non-phenolic sour water to Block 3000 and hydrocarbons to the fractionator heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the cold separator is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the cold separator is an affected source.

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

Under the NSPS, 40 CFR 60, Subpart Db, fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, the fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator heater is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator heater is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, fractionator heater EU-2004 is an affected source.

(16) One (1) fractionator tower, identified as Fractionator Tower, approved in 2018 for construction, discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix Drum, and non-phenolic sour water to Block 3000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the fractionator tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator tower is an affected source.

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

(A) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the HP Absorber and LP Absorber are affected sources.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the HP Absorber and LP Absorber is an affected source.

(e) Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

(A) One (1) heat exchanger, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) stripper column , identified as Stripper, approved in 2018 for construction, discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger and the reboiler and vapor to the overheads condenser, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(C) One (1) water-cooled condenser, identified as Overheads Condenser, approved in 2018 for construction, discharging condensate to the stripper condenser accumulator, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(D) One (1) accumulator drum, identified as Stripper Condenser Accumulator, approved in 2018 for construction, discharging condensate to stripper reflux and the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(E) One (1) steam-heated reboiler, identified as Stripper Reboiler, approved in 2018 for construction, discharging lean amine to the stripper reflux, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Amine Recovery Unit is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Amine Recovery Unit part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Amine Recovery Unit is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Amine Recovery Unit is an affected source.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Sour Water Stripping System is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Sour Water Stripping System is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Sour Water Stripping System is an affected source.

(3) Sulfur Recovery System, consisting of:

(A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors,

discharging treated gas to the TGTU A heat exchanger and molten sulfur to the sulfur product pit.

(v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.

(vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.

(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.

(viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.

(ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.

(x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605A Incinerator and A-605A Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit A is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit A is an affected source.

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.

(ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.

(iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.

(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.

(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.

(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.

(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.

(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.

(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.

(x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605B Incinerator and A-605B Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit B is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit B is an affected source.

(f) Offsites operations, identified as Block 4000, consisting of:

(1) Flares, as follows:

(A) One (1) natural gas and process fuel gas-fired flare identified as High Pressure (HP) Flare, approved in 2018 for construction, servicing overpressure and emergency reliefs from Block 2000 VEBA Combi Cracker operations, controlling emissions from Block 2000 depressurization system, with pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(B) One (1) natural gas and process fuel gas-fired flare, identified as Low Pressure (LP) Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 7000 Hydrogen Unit operations, controlling emissions Block 7000 start-up and shut-down vents, and a continuous sweep stream from the Block 2000 slop tank, with a sweep and pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(C) One (1) natural gas and process fuel gas-fired flare, identified as Sulfur Block Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 3000 Sulfur Recovery operations and sulfur loading, controlling emergency streams from Sulfur Recovery Units A and B, and a continuous sweep stream from the sour water storage tanks, with a sweep and pilot heat input capacity of 0.77 MMBtu/hr (LHV), exhausting to the atmosphere.

(D) One (1) natural gas and process fuel gas-fired flare, identified as Loading Flare, approved in 2018 for construction, servicing Block 4000 naphtha, diesel, and ammonia loading operations, with a pilot heat input capacity of 0.20 MMBtu/hr (LHV), exhausting to the atmosphere.

Under the NSPS, 40 CFR 60, Subpart Ja, the flares are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, the flares are affected facilities.

Under the NESHAP, 40 CFR 63, Subpart CC, the flares are affected sources.

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T1	IFR	Naphtha product	4,629,879 (17,524)	-
T2	IFR	Naphtha product	4,629,879 (17,524)	-
T3	FR	Diesel product	4,525,796 (17,130)	-
T4	FR	Diesel product	4,525,796 (17,130)	-
T5	FR	Diesel product	4,525,796 (17,130)	-
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)	-
T10	FR	Residue surge tank 1	926,980 (17,524)	-
T11	FR	Residue surge tank 2	926,980 (3,509)	-
T12	FR	Residue feed tank	926,980 (3,509)	-
T13	FR	VGO tank 1	926,980 (3,509)	-
T14	FR	VGO tank 2	926,980 (3,509)	-
T15	HPV	LPG storage	48,872 (185)	-

1. *FR - fixed roof, IFR - internal floating roof, HPV-horizontal pressure vessel*
2. *Tank vents to flares are part of sweep and pilot gas streams.*

Under the NSPS, 40 CFR 60, Subpart Kb, T1, T2, and T6 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, T1 - T6 and T10 - T15 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart QQQ, T16 is part of an affected facility.

Under the NSPS, 40 CFR 61, Subpart FF, T16 and T18 - T21 are part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, T1 - T6, T10 - T14, T16, and T18-T23 are part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart WW, T3 - T6 and T10 - T14 are affected sources.

(3) Loading operations, as follows:

(A) One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Product Loading Rack is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart BB, the Product Loading Rack is an affected source.

Under the NESHAP, 40 CFR 63, Subpart CC, the Product Loading Rack is an affected source.

(j) Hydrogen unit operations, identified as Block 7000, as follows:

(1) Hydrogen Plant 1, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7003, identified as Feed Water Treatment System 1, approved in 2018 for construction, using no controls and exhausting to stack EU-7003.

(B) One (1) feed preparation train, identified as Feed Prep 1, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7001, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-

7001, is an affected facility.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 1, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 1, approved in 2018 for construction, using no controls and discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 1 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 1 is an affected source.

(2) Hydrogen Plant 2, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7004, identified as Feed Water Treatment System 2, approved in 2018 for construction, using no controls and exhausting to stack EU-7004.

(B) One (1) feed preparation train, identified as Feed Prep 2, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7002, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 2, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 2, approved in 2018 for construction, using no controls and discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 2 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 2 is an affected source.

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

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

E.6.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart GGGa

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

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

E.6.2 Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 NSPS [326 IAC 12] [40 CFR Part 60, Subpart GGGa]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart GGGa (included as Attachment G to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.590a
(2) 40 CFR 60.591a
(3) 40 CFR 60.592a
(4) 40 CFR 60.593a

SECTION E.7 NSPS

Emissions Unit Description:

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(12) One (1) vacuum distillation tower, identified as Vacuum Distillation Column, approved in 2018 for construction, discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 4000, phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum distillation tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the vacuum distillation tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum distillation tower is an affected source.

(16) One (1) fractionator tower, identified as Fractionator Tower, approved in 2018 for construction, discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix Drum, and non-phenolic sour water to Block 3000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the fractionator tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator tower is an affected source.

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

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

E.7.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart NNN.

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

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

E.7.2 Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations NSPS [326 IAC 12] [40 CFR Part 60, Subpart NNN]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart NNN (included as Attachment H to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.660(a)
(2) 40 CFR 60.660(b)(3)
(3) 40 CFR 60.660(c)(4)
(4) 40 CFR 60.661
(5) 40 CFR 60.662
(6) 40 CFR 60.663(f)
(7) 40 CFR 60.664
(8) 40 CFR 60.665
(9) 40 CFR 60.666
(10) 40 CFR 60.667
(11) 40 CFR 60.668

SECTION E.8 NSPS

Emissions Unit Description:

(f) Offsites operations, identified as Block 4000, consisting of:

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T16	FR	Slop tank	4,195,581 (15,880)	LP flare

1. FR - fixed roof, IFR - internal floating roof, HPV-horizontal pressure vessel
2. Tank vents to flares are part of sweep and pilot gas streams.

Under the NSPS, 40 CFR 60, Subpart Kb, T1, T2, and T6 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, T1 - T6 and T10 - T15 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart QQQ, T16 is part of an affected facility.

Under the NSPS, 40 CFR 61, Subpart FF, T16 and T18 - T21 are part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, T1 - T6, T10 - T14, T16, and T18-T23 are part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart WW, T3 - T6 and T10 - T14 are affected sources.

(k) Wastewater treatment operations, identified as Block 8000, as follows:

(1) One (1) wastewater junction box with associated process drains, identified as Oily Water Sump, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8002.

(2) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Water Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and water to MH1.

(3) One (1) wastewater junction box with, identified as MH1, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8003.

(4) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Amine Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and amine solution to the Rich Amine Return Header.

(5) One (1) biological wastewater treatment system, approved in 2018 for construction, with emissions exhausting to vent EU-8001.

Under the NSPS, 40 CFR 60, Subpart QQQ, the process drains, junction boxes, Oily Water

Separator, Oily Amine Separator, associated sewer lines, and any secondary oil-water separator in the biological wastewater treatment system are an affected aggregate facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Oily Water Separator, Oily Amine Separator, and any secondary oil-water separator in the biological wastewater treatment system are affected sources.

Under the NESHAP, 40 CFR 63, Subpart CC, the wastewater streams and treatment operations associated with petroleum refining process units are part of a new affected source..

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

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

E.8.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart QQQ.

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

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

E.8.2 Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems NSPS [326 IAC 12] [40 CFR Part 60, Subpart QQQ]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart QQQ (included as Attachment I to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.690
(2) 40 CFR 60.691
(3) 40 CFR 60.692-1
(4) 40 CFR 60.692-2
(5) 40 CFR 60.692-3
(6) 40 CFR 60.692-4
(7) 40 CFR 60.692-5
(8) 40 CFR 60.692-6
(9) 40 CFR 60.692-7
(10) 40 CFR 60.693-1
(11) 40 CFR 60.693-2
(12) 40 CFR 60.694
(13) 40 CFR 60.695
(14) 40 CFR 60.696
(15) 40 CFR 60.697
(16) 40 CFR 60.698
(17) 40 CFR 60.699

SECTION E.9 NSPS

Emissions Unit Description:

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(9) One (1) first stage reactor - liquid phase hydrocracking system, identified as LPH, approved in 2018 for construction, discharging to the hot separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the first stage reactor - liquid phase hydrocracking system is an affected source.

(13) One (1) second stage reactor - gas phase hydrotreating system, identified as GPH, approved in 2018 for construction, discharging to the cold separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the second stage reactor - gas phase hydrotreating system is an affected source.

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

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

E.9.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart RRR.

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

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

E.9.2 Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes NSPS [326 IAC 12] [40 CFR Part 60, Subpart RRR]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart RRR (included as Attachment J to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.700(a)
(2) 40 CFR 60.700(b)(3)
(3) 40 CFR 60.700(c)(5)
(4) 40 CFR 60.701
(5) 40 CFR 60.705(r)
(6) 40 CFR 60.706
(7) 40 CFR 60.707
(8) 40 CFR 60.708

SECTION E.10 NSPS

Emissions Unit Description:

(h) Utilities operations, identified as Block 6000, consisting of:

(3) One (1) diesel engine-driven emergency generator, identified as EU-6006, approved in 2018 for construction, with a maximum heat input capacity of 19.60 MMBtu/hr (2,800 hp) (average heating value), using no add-on controls and exhausting to stack EU-6006.

Under the NSPS, 40 CFR 60, Subpart IIII, emergency generator EU-6006 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart ZZZZ, emergency generator EU-6006 is an affected source.

(4) One (1) diesel engine-driven emergency fire pump, identified as EU-6008, approved in 2018 for construction, with a maximum heat input capacity of 5.25 MMBtu/hr (750 hp) (average heating value), using no add-on controls and exhausting to stack EU-6008.

Under the NSPS, 40 CFR 60, Subpart IIII, emergency fire pump EU-6008 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart ZZZZ, emergency fire pump EU-6008 is an affected source.

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

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

E.10.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1][40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart IIII.

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

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

E.10.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines NSPS [326 IAC 12][40 CFR Part 60, Subpart IIII]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart IIII (included as Attachment K to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.4200(a)(2)
(2) 40 CFR 60.4200(a)(4)
(3) 40 CFR 60.4205(b)
(4) 40 CFR 60.4205(c)
(5) 40 CFR 60.4206
(6) 40 CFR 60.4207(b)
(7) 40 CFR 60.4208(a)
(8) 40 CFR 60.4209(a)
(9) 40 CFR 60.4211(a)
(10) 40 CFR 60.4211(c)
(11) 40 CFR 60.4211(f)(1)
(12) 40 CFR 60.4211(f)(2)(i)
(13) 40 CFR 60.4211(f)(3)
(14) 40 CFR 60.4211(g)(2)
(15) 40 CFR 60.4211(g)(3)
(16) 40 CFR 60.4214(b)
(17) 40 CFR 60.4218
(18) 40 CFR 60.4219
(19) Table 4 to Subpart IIII of Part 60
(20) Table 5 to Subpart IIII of Part 60
(21) Table 8 to Subpart IIII of Part 60

SECTION E.11 NESHAP

Emissions Unit Description:

(f) Offsites operations, identified as Block 4000, consisting of:

(3) Loading operations, as follows:

(A) One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Product Loading Rack is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart BB, the Product Loading Rack is an affected source.

Under the NESHAP, 40 CFR 63, Subpart CC, the Product Loading Rack is an affected source.

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

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

E.11.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 61 [326 IAC 14-1] [40 CFR Part 61, Subpart A]

(a) Pursuant to 40 CFR 61.01 the Permittee shall comply with the provisions of 40 CFR Part 61, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 14-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 61, Subpart BB.

(b) Pursuant to 40 CFR 61.04, the Permittee shall submit all required notifications and reports to:

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

E.11.2 National Emission Standard for Benzene Emissions From Benzene Transfer Operations NESHAP [40 CFR Part 61, Subpart BB]

The Permittee shall comply with the following provisions of 40 CFR Part 61, Subpart BB (included as Attachment L to the operating permit), for the emission unit(s) listed above:

(1) 40 CFR 61.300(a)
(2) 40 CFR 61.300(b)
(3) 40 CFR 61.304(i)

SECTION E.12 NESHAP

Emissions Unit Description:

(e) Sulfur recovery operations, identified as Block 3000, consisting of:

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Sour Water Stripping System is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Sour Water Stripping System is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Sour Water Stripping System is an affected source.

(f) Offsites operations, identified as Block 4000, consisting of:

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T16	FR	Slop tank	4,195,581 (15,880)	LP flare
T18	FR	Non-phenolic sour water storage tank 1	1,268,026 (4,799)	SB flare
T19	FR	Non-phenolic sour water storage tank 2	1,268,026 (4,799)	SB flare
T20	FR	Non-phenolic sour water storage tank 3	1,268,026 (4,799)	SB flare
T21	FR	Phenolic sour water storage tank	40,947 (155)	SB flare

1. FR - fixed roof, IFR - internal floating roof, HPV-horizontal pressure vessel

2. *Tank vents to flares are part of sweep and pilot gas streams.*

Under the NSPS, 40 CFR 60, Subpart Kb, T1, T2, and T6 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, T1 - T6 and T10 - T15 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart QQQ, T16 is part of an affected facility.

Under the NSPS, 40 CFR 61, Subpart FF, T16 and T18 - T21 are part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, T1 - T6, T10 - T14, T16, and T18-T23 are part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart WW, T3 - T6 and T10 - T14 are affected sources.

(k) Wastewater treatment operations, identified as Block 8000, as follows:

(1) One (1) wastewater junction box with associated process drains, identified as Oily Water Sump, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8002.

(2) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Water Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and water to MH1.

(3) One (1) wastewater junction box with, identified as MH1, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8003.

(4) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Amine Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and amine solution to the Rich Amine Return Header.

(5) One (1) biological wastewater treatment system, approved in 2018 for construction, with emissions exhausting to vent EU-8001.

Under the NSPS, 40 CFR 60, Subpart QQQ, the process drains, junction boxes, Oily Water Separator, Oily Amine Separator, associated sewer lines, and any secondary oil-water separator in the biological wastewater treatment system are an affected aggregate facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Oily Water Separator, Oily Amine Separator, and any secondary oil-water separator in the biological wastewater treatment system are affected sources.

Under the NESHAP, 40 CFR 63, Subpart CC, the wastewater streams and treatment operations associated with petroleum refining process units are part of a new affected source..

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

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

E.12.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 61 [326 IAC 14-1] [40 CFR Part 61, Subpart A]

(a) Pursuant to 40 CFR 61.01 the Permittee shall comply with the provisions of 40 CFR Part 61, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 14-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 61, Subpart FF.

(b) Pursuant to 40 CFR 61.04, the Permittee shall submit all required notifications and reports to:

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

E.12.2 National Emission Standards for Benzene Waste Operations NESHAP [40 CFR Part 61, Subpart FF]

The Permittee shall comply with the following provisions of 40 CFR Part 61, Subpart FF (included as Attachment M to the operating permit), for the emission unit(s) listed above:

(1) 40 CFR 61.340
(2) 40 CFR 61.341
(3) 40 CFR 61.343
(4) 40 CFR 61.346
(5) 40 CFR 61.347
(6) 40 CFR 61.348
(7) 40 CFR 61.349
(8) 40 CFR 61.350
(9) 40 CFR 61.351
(10) 40 CFR 61.352
(11) 40 CFR 61.353
(12) 40 CFR 61.354
(13) 40 CFR 61.355
(14) 40 CFR 61.356
(15) 40 CFR 61.357
(16) 40 CFR 61.358

SECTION E.13 NESHAP

Emissions Unit Description:

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(5) One (1) nitrogen-blanketed Na_2S slurry preparation system, identified as Na_2S Slurry Preparation, approved in 2018 for construction, with a maximum capacity of 0.077 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Na_2S Handling System Filter, exhausting to stack EU-2008, consisting of:

(A) One (1) Na_2S silo rotary feeder solid weigh scale.
(B) One (1) Na_2S screw conveyor discharging to the Na_2S mixing drum.
(C) One (1) nitrogen-blanketed mixing drum for Na_2S and Block 2000 vacuum tower VGO (vacuum gas oil) discharging to the feed premix drum.

Under the NSPS, 40 CFR 60, Subpart GGGa, the mixing drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the mixing drum is an affected source.

(6) One (1) feed premix drum, identified as Feed Premix Drum, approved in 2018 for construction, receiving coal, solid additives, and recycled vacuum gas oil (VGO) and discharging to the feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed premix drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed premix drum is an affected source.

(7) One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2018 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

Under the NSPS, 40 CFR 60, Subpart Ja, the feed heater EU-2001 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed heater EU-2001 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed heater EU-2001 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, feed heater EU-2001 is an affected source.

(9) One (1) first stage reactor - liquid phase hydrocracking system, identified as LPH, approved in 2018 for construction, discharging to the hot separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the first stage reactor - liquid phase hydrocracking system is an affected source.

(10) One (1) hot separator, identified as Hot Separator, approved in 2018 for construction, discharging vapor to the 2nd stage reactors and liquids to the vacuum column feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the hot separator is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the hot separator is an affected source.

(11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the vacuum distillation tower, exhausting to stack EU-2003.

Under the NSPS, 40 CFR 60, Subpart Ja, the vacuum column feed heater EU-2003 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum column feed heater EU-2003 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum column feed heater EU-2003 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, vacuum column feed heater EU-2003 is an affected source.

(12) One (1) vacuum distillation tower, identified as Vacuum Distillation Column, approved in 2018 for construction, discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 4000, phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum distillation tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the vacuum distillation tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum distillation tower is an affected source.

(13) One (1) second stage reactor - gas phase hydrotreating system, identified as GPH, approved in 2018 for construction, discharging to the cold separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the second stage reactor - gas phase hydrotreating system is an affected source.

(14) One (1) cold separator , identified as Cold Separator, approved in 2018 for construction, discharging non-phenolic sour water to Block 3000 and hydrocarbons to the fractionator heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the cold separator is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the cold separator is an affected source.

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

Under the NSPS, 40 CFR 60, Subpart Db, fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, the fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator heater is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator heater is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, fractionator heater EU-2004 is an affected source.

(16) One (1) fractionator tower, identified as Fractionator Tower, approved in 2018 for construction, discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix Drum, and non-phenolic sour water to Block 3000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the fractionator tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator tower is an affected source.

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

(A) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the HP Absorber and LP Absorber are affected sources.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the HP Absorber and LP Absorber is an affected source.

(e) Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

(A) One (1) heat exchanger, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) stripper column , identified as Stripper, approved in 2018 for construction, discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger and the reboiler and vapor to the overheads condenser, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(C) One (1) water-cooled condenser, identified as Overheads Condenser, approved in 2018 for construction, discharging condensate to the stripper condenser accumulator, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(D) One (1) accumulator drum, identified as Stripper Condenser Accumulator, approved in 2018 for construction, discharging condensate to stripper reflux and the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(E) One (1) steam-heated reboiler, identified as Stripper Reboiler, approved in 2018 for construction, discharging lean amine to the stripper reflux, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Amine Recovery Unit is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Amine Recovery Unit part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Amine Recovery Unit is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Amine Recovery Unit is an affected source.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Sour Water Stripping System is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Sour Water Stripping System is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Sour Water Stripping System is an affected source.

(3) Sulfur Recovery System, consisting of:

(A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors,

discharging treated gas to the TGTU A heat exchanger and molten sulfur to the sulfur product pit.

(v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.

(vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.

(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.

(viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.

(ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.

(x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605A Incinerator and A-605A Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit A is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit A is an affected source.

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.

(ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.

(iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.

(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.

(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.

(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.

(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.

(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.

(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.

(x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605B Incinerator and A-605B Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit B is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit B is an affected source.

(f) Offsites operations, identified as Block 4000, consisting of:

(1) Flares, as follows:

(A) One (1) natural gas and process fuel gas-fired flare identified as High Pressure (HP) Flare, approved in 2018 for construction, servicing overpressure and emergency reliefs from Block 2000 VEBA Combi Cracker operations, controlling emissions from Block 2000 depressurization system, with pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(B) One (1) natural gas and process fuel gas-fired flare, identified as Low Pressure (LP) Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 7000 Hydrogen Unit operations, controlling emissions Block 7000 start-up and shut-down vents, and a continuous sweep stream from the Block 2000 slop tank, with a sweep and pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(C) One (1) natural gas and process fuel gas-fired flare, identified as Sulfur Block Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 3000 Sulfur Recovery operations and sulfur loading, controlling emergency streams from Sulfur Recovery Units A and B, and a continuous sweep stream from the sour water storage tanks, with a sweep and pilot heat input capacity of 0.77 MMBtu/hr (LHV), exhausting to the atmosphere.

(D) One (1) natural gas and process fuel gas-fired flare, identified as Loading Flare, approved in 2018 for construction, servicing Block 4000 naphtha, diesel, and ammonia loading operations, with a pilot heat input capacity of 0.20 MMBtu/hr (LHV), exhausting to the atmosphere.

Under the NSPS, 40 CFR 60, Subpart Ja, the flares are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, the flares are affected facilities.

Under the NESHAP, 40 CFR 63, Subpart CC, the flares are affected sources.

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T1	IFR	Naphtha product	4,629,879 (17,524)	-
T2	IFR	Naphtha product	4,629,879 (17,524)	-
T3	FR	Diesel product	4,525,796 (17,130)	-
T4	FR	Diesel product	4,525,796 (17,130)	-
T5	FR	Diesel product	4,525,796 (17,130)	-
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)	-
T10	FR	Residue surge tank 1	926,980 (17,524)	-
T11	FR	Residue surge tank 2	926,980 (3,509)	-
T12	FR	Residue feed tank	926,980 (3,509)	-
T13	FR	VGO tank 1	926,980 (3,509)	-
T14	FR	VGO tank 2	926,980 (3,509)	-
T16	FR	Slop tank	4,195,581 (15,880)	LP flare
T18	FR	Non-phenolic sour water storage tank 1	1,268,026 (4,799)	SB flare
T19	FR	Non-phenolic sour water storage tank 2	1,268,026 (4,799)	SB flare

T20	FR	Non-phenolic sour water storage tank 3	1,268,026 (4,799)	SB flare
T21	FR	Phenolic sour water storage tank	40,947 (155)	SB flare
T22	FR	Stripped non-phenolic sour water surge tank	1,268,026 (4,799)	-
T23	FR	Stripped phenolic sour water surge tank	13,737 (52)	-

1. *FR - fixed roof, IFR - internal floating roof, HPV-horizontal pressure vessel*
2. *Tank vents to flares are part of sweep and pilot gas streams.*

Under the NSPS, 40 CFR 60, Subpart Kb, T1, T2, and T6 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, T1 - T6 and T10 - T15 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart QQQ, T16 is part of an affected facility.

Under the NSPS, 40 CFR 61, Subpart FF, T16 and T18 - T21 are part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, T1 - T6, T10 - T14, T16, and T18-T23 are part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart WW, T3 - T6 and T10 - T14 are affected sources.

(3) Loading operations, as follows:

(A) One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Product Loading Rack is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart BB, the Product Loading Rack is an affected source.

Under the NESHAP, 40 CFR 63, Subpart CC, the Product Loading Rack is an affected source.

(j) Hydrogen unit operations, identified as Block 7000, as follows:

(1) Hydrogen Plant 1, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7003, identified as Feed Water Treatment System 1, approved in 2018 for construction, using no controls and exhausting to stack EU-7003.

(B) One (1) feed preparation train, identified as Feed Prep 1, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.

(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7001, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7001, is an affected facility.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 1, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 1, approved in 2018 for construction, using no controls and discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 1 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 1 is an affected source.

(2) Hydrogen Plant 2, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7004, identified as Feed Water Treatment System 2, approved in 2018 for construction, using no controls and exhausting to stack EU-7004.

(B) One (1) feed preparation train, identified as Feed Prep 2, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7002, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7003, is an affected facility.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 2, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 2, approved in 2018 for construction, using no controls and discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 2 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 2 is an affected source.

(k) Wastewater treatment operations, identified as Block 8000, as follows:

(1) One (1) wastewater junction box with associated process drains, identified as Oily Water Sump, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8002.

(2) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Water Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and water to MH1.

(3) One (1) wastewater junction box with, identified as MH1, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8003.

(4) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Amine Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and amine solution to the Rich Amine Return Header.

(5) One (1) biological wastewater treatment system, approved in 2018 for construction, with emissions exhausting to vent EU-8001.

Under the NSPS, 40 CFR 60, Subpart QQQ, the process drains, junction boxes, Oily Water Separator, Oily Amine Separator, associated sewer lines, and any secondary oil-water separator in the biological wastewater treatment system are an affected aggregate facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Oily Water Separator, Oily Amine Separator, and any secondary oil-water separator in the biological wastewater treatment system are affected sources.

Under the NESHAP, 40 CFR 63, Subpart CC, the wastewater streams and treatment operations associated with petroleum refining process units are part of a new affected source..

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

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

E.13.1 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 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart CC.

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

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

E.13.2 National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries NESHAP [40 CFR Part 63, Subpart CC] [326 IAC 20-16]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart CC (included as Attachment N to the operating permit), which are incorporated by reference as 326 IAC 20-16, for the emission unit(s) listed above:

(1) 40 CFR 63.640(a)
(2) 40 CFR 63.640(c)
(3) 40 CFR 63.640(d)
(4) 40 CFR 63.640(e)
(5) 40 CFR 63.640(f)
(6) 40 CFR 63.640(h)
(7) 40 CFR 63.640(k)
(8) 40 CFR 63.640(m)
(9) 40 CFR 63.640(n)(2)
(10) 40 CFR 63.640(n)(8)
(11) 40 CFR 63.640(o)(1)
(12) 40 CFR 63.640(p)(2)
(13) 40 CFR 63.641
(14) 40 CFR 63.642
(15) 40 CFR 63.643
(16) 40 CFR 63.644
(17) 40 CFR 63.645
(18) 40 CFR 63.647
(19) 40 CFR 63.654
(20) 40 CFR 63.655
(21) 40 CFR 63.656
(22) 40 CFR 63.658
(23) Table 11 to Subpart CC of Part 63

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

E.13.2 Testing Requirements [326 IAC 2-1.1-11] [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

In order to document the compliance status with Condition E.13.2, the Permittee shall perform the testing required under 40 CFR 63, Subpart CC, utilizing methods as approved by the Commissioner, at least once every five (5) years from the date of the most recent valid compliance demonstration.

Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

SECTION E.14 NESHAP

Emissions Unit Description:

(f) Offsites operations, identified as Block 4000, consisting of:

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T3	FR	Diesel product	4,525,796 (17,130)	-
T4	FR	Diesel product	4,525,796 (17,130)	-
T5	FR	Diesel product	4,525,796 (17,130)	-
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)	-
T10	FR	Residue surge tank 1	926,980 (17,524)	-
T11	FR	Residue surge tank 2	926,980 (3,509)	-
T12	FR	Residue feed tank	926,980 (3,509)	-
T13	FR	VGO tank 1	926,980 (3,509)	-
T14	FR	VGO tank 2	926,980 (3,509)	-

1. *FR - fixed roof, IFR - internal floating roof, HPV-horizontal pressure vessel*
2. *Tank vents to flares are part of sweep and pilot gas streams.*

Under the NSPS, 40 CFR 60, Subpart Kb, T1, T2, and T6 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, T1 - T6 and T10 - T14 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart QQQ, T16 is part of an affected facility.

Under the NSPS, 40 CFR 61, Subpart FF, T16 and T18 - T21 are part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, T1 - T6, T10 - T14, T16, and T18-T23 are part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart WW, T3 - T6 and T10 - T14 are affected sources.

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

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

E.14.1 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 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart WW.

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

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

E.14.2 National Emission Standards for Storage Vessels (Tanks) - Control Level 2 NESHAP [40 CFR Part 63, Subpart WW] [326 IAC 20-43]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart WW (included as Attachment O to the operating permit), which are incorporated by reference as 326 IAC 20-43, for the emission unit(s) listed above:

1) 40 CFR 63.1060
(2) 40 CFR 63.1061
(3) 40 CFR 63.1065(a)
(4) 40 CFR 63.1067

SECTION E.15 NESHAP

Emissions Unit Description:

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

(A) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the HP Absorber and LP Absorber are affected sources.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the HP Absorber and LP Absorber is an affected source.

(e) Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

(A) One (1) heat exchanger, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) stripper column , identified as Stripper, approved in 2018 for construction, discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger and the reboiler and vapor to the overheads condenser, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(C) One (1) water-cooled condenser, identified as Overheads Condenser, approved in 2018 for construction, discharging condensate to the stripper condenser accumulator, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(D) One (1) accumulator drum, identified as Stripper Condenser Accumulator, approved in 2018 for construction, discharging condensate to stripper reflux and the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(E) One (1) steam-heated reboiler, identified as Stripper Reboiler, approved in 2018 for construction, discharging lean amine to the stripper reflux, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Amine Recovery Unit is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Amine Recovery Unit part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Amine Recovery Unit is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Amine Recovery Unit is an affected source.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Sour Water Stripping System is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Sour Water Stripping System is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Sour Water Stripping System is an affected source.

(3) Sulfur Recovery System, consisting of:

(A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in

2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the TGTU A heat exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
(xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605A Incinerator and A-605A Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit A is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit A is an affected source.

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

- (i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
- (ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.
- (iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
- (iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.
- (v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
- (vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
- (vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.
- (viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
- (ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
- (x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
- (xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

  Under the NSPS, 40 CFR 60, Subpart Dc, the A-605B Incinerator and A-605B Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit B is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit B is an affected source.

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

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

E.15.1 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 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart UUU.

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

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

E.15.2 National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units NESHAP [40 CFR Part 63, Subpart UUU] [326 IAC 20-50]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart UUU (included as Attachment P to the operating permit), which are incorporated by reference as 326 IAC 20-50, for the emission unit(s) listed above:

(1) 40 CFR 63.1560
(2) 40 CFR 63.1561
(3) 40 CFR 63.1562(a)
(4) 40 CFR 63.1562(b)(3)
(5) 40 CFR 63.1562(b)(4)
(6) 40 CFR 63.1562(c)
(7) 40 CFR 63.1563(a)(2)
(8) 40 CFR 63.1563(f)
(9) 40 CFR 63.1568(a)(1)
(10) 40 CFR 63.1569
(11) 40 CFR 63.1570
(12) 40 CFR 63.1571
(13) 40 CFR 63.1572
(14) 40 CFR 63.1573
(15) 40 CFR 63.1574
(16) 40 CFR 63.1575
(17) 40 CFR 63.1576
(18) 40 CFR 63.1577
(19) 40 CFR 63.1578
(20) 40 CFR 63.1579
(21) Table 36 to Subpart UUU of Part 63
(22) Table 37 to Subpart UUU of Part 63
(23) Table 38 to Subpart UUU of Part 63
(24) Table 39 to Subpart UUU of Part 63

SECTION E.16 NESHAP

Emissions Unit Description:

(h) Utilities operations, identified as Block 6000, consisting of:

(3) One (1) diesel engine-driven emergency generator, identified as EU-6006, approved in 2018 for construction, with a maximum heat input capacity of 19.60 MMBtu/hr (2,800 hp) (average heating value), using no add-on controls and exhausting to stack EU-6006.

Under the NSPS, 40 CFR 60, Subpart IIII, emergency generator EU-6006 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart ZZZZ, emergency generator EU-6006 is an affected source.

(4) One (1) diesel engine-driven emergency fire pump, identified as EU-6008, approved in 2018 for construction, with a maximum heat input capacity of 5.25 MMBtu/hr (750 hp) (average heating value), using no add-on controls and exhausting to stack EU-6008.

Under the NSPS, 40 CFR 60, Subpart IIII, emergency fire pump EU-6008 is an affected facility.

(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.16.1 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 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart ZZZZ.

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

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

E.16.2 Stationary Reciprocating Internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ][326 IAC 20-82]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart ZZZZ (included as Attachment Q to the operating permit), which are incorporated by reference as 326 IAC 20-82, for the emission unit(s) listed above:

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585

(3) 40 CFR 63.6590(a)(2)(i)
(4) 40 CFR 63.6590(b)(1)(i)
(5) 40 CFR 63.6640(f)(1)
(6) 40 CFR 63.6640(f)(2)(i)
(7) 40 CFR 63.6640(f)(3)
(8) 40 CFR 63.6645(f)
(9) 40 CFR 63.6665
(10) 40 CFR 63.6670
(11) 40 CFR 63.6675
(12) Table 8 to Subpart ZZZZ of Part 63

SECTION E.17 NESHAP

Emissions Unit Description:

(b) Coal drying loop, collectively identified as EU-1008, with emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008, consisting of the following:

(3) One (1) natural gas and process fuel gas-fired heater, identified as Coal Dryer Heater EU-1007, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 55.8 MMBtu/hr (HHV), with emissions exhausting to Stack EU-1007.

Under the NSPS, 40 CFR 60, Subpart Ja, the Coal Dryer Heater (EU-1007) is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Heater (EU-1007) is part of an affected thermal dryer.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, the Coal Dryer Heater (EU-1007) is an affected source.

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(7) One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2018 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

Under the NSPS, 40 CFR 60, Subpart Ja, the feed heater EU-2001 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed heater EU-2001 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed heater EU-2001 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, feed heater EU-2001 is an affected source.

(8) One (1) natural gas and process fuel gas-fired indirect treat gas heater, identified as EU-2002, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 52.8 MMBtu/hr (HHV), receiving hydrogen from Block 7000 and discharging to the 1st stage reactors, exhausting to stack EU-2002.

Under the NSPS, 40 CFR 60, Subpart Ja, the treat gas heater EU-2002 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, treat gas heater EU-2002 is an affected source.

(11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the

vacuum distillation tower, exhausting to stack EU-2003.

Under the NSPS, 40 CFR 60, Subpart Ja, the vacuum column feed heater EU-2003 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum column feed heater EU-2003 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum column feed heater EU-2003 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, vacuum column feed heater EU-2003 is an affected source.

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

Under the NSPS, 40 CFR 60, Subpart Db, fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, the fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator heater is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator heater is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, fractionator heater EU-2004 is an affected source.

(h) Utilities operations, identified as Block 6000, consisting of:

(1) One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 68.50 MMBtu/hr (HHV), exhausting to stack EU-6000.

Under the NSPS, 40 CFR 60, Subpart Dc, boiler EU-6000 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, boiler EU-6000 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, boiler EU-6000 is an affected source.

(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.17.1 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 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart DDDDD.

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

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

E.17.2 National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP [40 CFR Part 63, Subpart DDDDD][326 IAC 20-95]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart DDDDD (included as Attachment R to the operating permit), which are incorporated by reference as 326 IAC 20-95, for the emission unit(s) listed above:

(1) 40 CFR 63.7480
(2) 40 CFR 63.7485
(3) 40 CFR 63.7490(a)(2)
(4) 40 CFR 63.7490(b)
(5) 40 CFR 63.7495(a)
(6) 40 CFR 63.7495(d)
(7) 40 CFR 63.7495(i)
(8) 40 CFR 63.7499(l)
(9) 40 CFR 63.7500(a)(1)
(10) 40 CFR 63.7500(a)(3)
(11) 40 CFR 63.7500(b)
(12) 40 CFR 63.7500(e)
(13) 40 CFR 63.7500(f)
(14) 40 CFR 63.7505(a)
(15) 40 CFR 63.7510(g)
(16) 40 CFR 63.7510(k)
(17) 40 CFR 63.7515(d)
(18) 40 CFR 63.7515(g)
(19) 40 CFR 63.7521(f)(1)
(20) 40 CFR 63.7530(f)
(21) 40 CFR 63.7540(a)(10)
(22) 40 CFR 63.7540(a)(11)
(23) 40 CFR 63.7540(a)(12)
(24) 40 CFR 63.7540(a)(13)
(25) 40 CFR 63.7540(b)
(26) 40 CFR 63.7540(d)
(27) 40 CFR 63.7545(a)
(28) 40 CFR 63.7545(c)
(29) 40 CFR 63.7545(e)

(30) 40 CFR 63.7545(h)
(31) 40 CFR 63.7550(a)
(32) 40 CFR 63.7550(b)
(33) 40 CFR 63.7550(c)(1)
(34) 40 CFR 63.7550(h)(3)
(35) 40 CFR 63.7555(a)
(36) 40 CFR 63.7555(h)
(37) 40 CFR 63.7560
(38) 40 CFR 63.7565
(39) 40 CFR 63.7570
(40) 40 CFR 63.7575
(41) Table 3 to Subpart DDDDD of Part 63 (item 1 (contin oxy trim), 2 (no trim, vac col feed) 3 (no trim all others))
(42) Table 9 to Subpart DDDDD of Part 63
(43) Table 10 to Subpart DDDDD of Part 63

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

Source Name:	Riverview Energy Corporation
Source Address:	4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.:	T147-39554-00065

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify)

☐ Report (specify)

☐ Notification (specify)

☐ Affidavit (specify)

☐ Other (specify)

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:

Printed Name:

Title/Position:

Phone:

Date:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
Phone: (317) 233-0178
Fax: (317) 233-6865

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name:	Riverview Energy Corporation
Source Address:	4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.:	T147-39554-00065

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

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

- The Permittee must notify the Office of Air Quality (OAQ), within four (**4**) daytime business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and
- The Permittee must submit notice in writing or by facsimile within two (**2**) working days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.

If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:
Control Equipment:
Permit Condition or Operation Limitation in Permit:
Description of the Emergency:
Describe the cause of the Emergency:

If any of the following are not applicable, mark N/A **Page 2 of 2**

Date/Time Emergency started:
Date/Time Emergency was corrected:
Was the facility being properly operated at the time of the emergency? Y N
Type of Pollutants Emitted: TSP, PM-10, SO_2, VOC, NO_X, CO, Pb, other:
Estimated amount of pollutant(s) emitted during emergency:
Describe the steps taken to mitigate the problem:
Describe the corrective actions/response steps taken:
Describe the measures taken to minimize emissions:
If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:

Form Completed by:______________________________

Title / Position: __________________________________

Date:____

Phone: ____

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

Part 70 Quarterly Report

Source Name:	Riverview Energy Corporation
Source Address:	4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.:	T147-39554-00065
Facility:	Fuel gas combustion units, sulfur recovery units, flares, emergency engines, hydrogen plants
Parameter:	CO_2e emissions
Limit:	limits in tons per twelve (12) consecutive month period with compliance determined at the end of each month

Unit	Limit	Unit	Limit
EU-1007	29,127	SB Flare	448
EU-2001	67,023	EU-6000	35,756
EU-2002	27,561	EU-6006	811
EU-2003	4,698	EU-6008	217
EU-2004	81,430	EU-7001	986,271
SRU A & SRU B	40,872	EU-7002	986,271
Loading Flare	559	EU-7003	1,080
HP Flare	3,781	EU-7004	1,080
LP Flare	3,781		

QUARTER : ________________ YEAR: ____________________

Unit	Month	Column 1	Column 2	Column 3
		This Month (tons)	Previous 11 Months (tons)	12 Month Total (tons)
EU-1007				
EU-2001				
EU-2002				

Unit	Month	Column 1 This Month (tons)	Column 2 Previous 11 Months (tons)	Column 3 12 Month Total (tons)
EU-2003				
EU-2004				
SRU B & SRU B				
Loading Flare				
HP Flare				
LP Flare				
SB Flare				
EU-6000				
EU-6006				
EU-6008				

Unit	Month	Column 1	Column 2	Column 3
		This Month (tons)	Previous 11 Months (tons)	12 Month Total (tons)
EU-7001				
EU-7002				
EU-7003				
EU-7004				

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Riverview Energy Corporation
Source Address:	4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.:	T147-39554-00065
Facility:	Slop tank T16, sour water tanks T18-T21
Parameter:	Monthly throughput
Limit:	The slop tank and sour water tank throughput shall not exceed the values shown in the table below per twelve (12) consecutive month period with compliance determined at the end of each month

Unit	**Limit (kgal)**	**Unit**	**Limit (kgal)**
T16	305,467	T20	462,829
T18	462,829	T21	4,628
T19	462,829		

QUARTER : ________________ YEAR: ____________________

Unit	Month	Column 1	Column 2	Column 3
		This Month (kgal)	Previous 11 Months (kgal)	12 Month Total (kgal)
T16				
T18				
T19				
T20				
T21				

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Riverview Energy Corporation
Source Address:	4704 E 2000 N, Dale, Indiana 47523
Part 70 Permit No.:	T147-39554-00065
Facility:	Swing tank, T6
Parameter:	Compliance determination coefficient, C
Limit:	In any twelve (12) consecutive month period during which tank T6 changes between naphtha and diesel service, tank T6 shall be determined to in compliance with the VOC emission limit in Condition D.6.1 if the result, C, of the calculation below is less than or equal to 1.

$$C = \frac{D_N \times 6.29}{2{,}295} + \frac{(365 - D_N) \times 0.95}{345}$$

Where C = compliance determination coefficient
D_N = actual number of days in naphtha service during the twelve (12) consecutive month period

QUARTER : ________________ YEAR: ____________________

Month	Column 1	Column 2	Column 1 + Column 2	Compliance Determination Coefficient
	This Month (days in naphtha service)	Previous 11 Months (days in naphtha service)	12 Month Total (days in naphtha service)	

☐ No change in product service occurred in the twelve (12) consecutive month period.

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Riverview Energy Corporation
Source Address:	4704 E 2000 N, Dale, Indiana 47523
Part 70 Permit No.:	T147-39554-00065
Facility:	Emergency generator, EU-6006
Parameter:	Hours of operation
Limit:	Emergency generator (EU-6006) shall not exceed 100 hours of operation, per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : ________________ YEAR: ____________________

Month	Column 1	Column 2	Column 1 + Column 2
	This Month (hours)	Previous 11 Months (hours)	12 Month Total (hours)

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Riverview Energy Corporation
Source Address:	4704 E 2000 N, Dale, Indiana 47523
Part 70 Permit No.:	T147-39554-00065
Facility:	Emergency fire pump, EU-6008
Parameter:	Hours of operation
Limit:	Emergency fire pump (EU-6008) shall not exceed 200 hours of operation, per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : ________________ YEAR: ____________________

Month	Column 1	Column 2	Column 1 + Column 2
	This Month (hours)	Previous 11 Months (hours)	12 Month Total (hours)

☐ No deviation occurred in this quarter.

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

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

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

Source Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: T147-39554-00065

Months: __________ to __________ Year: ____________

Page 1 of 2

This report shall be submitted quarterly based on a calendar year. Proper notice submittal under Section B –Emergency Provisions satisfies the reporting requirements of paragraph (a) of Section C-General Reporting. Any deviation from the requirements of this permit, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".	
☐ NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.	
☐ THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

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: ____

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

Riverview Energy Corporation
4704 E 200 N
Dale, Indiana 47523

Affidavit of Construction

I, ____, being duly sworn upon my oath, depose and say:
(Name of the Authorized Representative)

1. I live in ______________________________ County, Indiana and being of sound mind and over twenty-one (21) years of age, I am competent to give this affidavit.

2. I hold the position of ________________________ for ________________________.
(Title) (Company Name)

3. By virtue of my position with ______________________________, I have personal
(Company Name)
knowledge of the representations contained in this affidavit and am authorized to make these representations on behalf of ____.
(Company Name)

4. I hereby certify that Riverview Energy Corporation, 4704 E 2000 N, Dale, IN 47523, completed construction of the direct coal hydrogenation facility on ______________________in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on January 25, 2018 and as permitted pursuant to New Source Construction Permit and Part 70 Operating Permit No. T147-39554-00065, Plant ID No. 147-00065 issued on __________.

5. **Permittee, please cross out the following statement if it does not apply:** Additional (operations/facilities) were constructed/substituted as described in the attachment to this document and were not made in accordance with the construction permit.

Further Affiant said not.

I affirm under penalties of perjury that the representations contained in this affidavit are true, to the best of my information and belief.

Signature____
Date____

STATE OF INDIANA)
)SS

COUNTY OF ______________________)

Subscribed and sworn to me, a notary public in and for ________________________ County and State of Indiana

on this ____________________ day of __________________, 20 _____. My Commission expires: _______________.

Signature________________________________
Name___________________________ (typed or printed)

Attachment A

Part 70 Operating Permit No: 147-39554-00065

Fugitive Dust Control Plan for Paved Roads as Required by 326 IAC 2-2-3

1. Source Information:

Name of Source:	Riverview Energy Corporation
Address of Source:	4704 East County Road 2000 North, Dale, IN, 47523
Source Contact Person and Title:	Gregory Merle
Source Contact Mailing Address:	15 E Putnam Ave, Suite# 210, Greenwich, CT 06830
Source Contact Telephone Number:	(203) 979 – 3993

2. Description of Processes, Operations, and Areas that Potentially Emit Fugitive Dust:

Process, Operation, or Area	Equipment Used	Additional Detail
Paved Roads and Parking Lots	All plant roads and parking lots are paved.	See road identifications in attached drawing used for air dispersion modeling input.
Transporting of Materials	VCC Sodium Sulfide Additive is transported to site by tank truck. Water treatment lime is transported to site by tank truck. Miscellaneous small quantity water and wastewater treatment chemicals are transported to site by tank truck or in containers by trailer truck. VCC co-product Residue, is primarily transported from site by railroad hopper cars and in limited periods by trailer trucks VCC co-product anhydrous ammonia is transported by tank truck.	Coal feedstock is transported to site by railroad hopper cars with unloading in enclosed building with ventilation system control by baghouse. VCC Fine and Coarse Additives are transported to site by railroad tank cars. Diesel and naphtha products are transported from site by railroad tank cars. VCC co-product liquid sulfur is transported by railroad tank cars.

Process, Operation, or Area	Equipment Used	Additional Detail
Loading and Unloading to and from Feed Bins, Hoppers, Silos, and Material Hauling Vehicles	Small quantity volumes of pastilles may be loaded into containers within Block 5000 Pastille Building and transported from site by trailer truck. Unloading of lime for water treatment uses pneumatic conveying system with baghouse control.	Unloading and transfers of coal use enclosed conveyors. Loading of VCC Unit Residue pastilles to rail cars and truck loading spots uses enclosed conveyors to storage hoppers and gravity chutes which are controlled by baghouses/ Unloading of VCC Process additives to storage silos and transfers to process use pneumatic conveying systems with baghouse controls. Lime transfer to slaking uses close coupled enclosed gravimetric conveying. Pneumatic systems use plant nitrogen supply as conveying gas.
Crushing, Grinding, Screening, Mixing, Conveying, and Transfer of Materials	No Crushing, Grinding, Screening, Mixing, Conveying, and Transfer of Materials impacts paved roads	Coal mill/pulverizer/dryer system is used to prepare coal feedstock feed to VCC Unit. Pulverized coal is conveyed from the Coal Dryer Baghouse to the VCC process by close coupled enclosed gravimetric conveying system. Fine Additive Production System Package grinds Coarse Additive to produce Fine Additive as backup supply system. Transfers are by closed gravity and pneumatic conveying systems.

3. Type of Vehicles and Average Daily Traffic on Site Roads:

Traffic Type	Vehicle Type and Capacity	Maximum Weight of Vehicle (tons)	Maximum Weight of Load (tons)	Maximum Weight of Vehicle and Load (tons/trip)	Maximum one-way trips per day (trip/day)	Maximum one-way distance (feet/trip)
Na2S Unloading	Truck	20	20	40	1.0	2133
Aniline	Truck	20	20	40	1.0	1640
DMDS	Truck	20	20	40	1.0	1640
Amine Make-up	Truck	20	20	40	1.0	1804
Ammonia Loading	Truck	20	20	40	5.0	2953
Molten Sulfur Loading	Truck	20	20	40	9.0	984
Residue Loading	Truck	20	20	40	62.0	984
Sulfuric Acid Unloading	Truck	20	20	40	1.0	820
Caustic Unloading	Truck	20	20	40	1.0	820
Boiler Feed WaterTreatment Chemicals Unloading	Truck	20	20	40	1.0	820
Diesel Fuel Unloading	Truck	20	20	40	1.0	820
Lime Unloading	Truck	20	20	40	1.0	1312
Water Treatment Chemicals Unloading	Truck	20	20	40	1.0	1312
Lime Sludge Loading	Truck	20	20	40	1.0	1312
Wastewater Treatment Chemicals Unloading	Truck	20	20	40	1.0	1640

Traffic Type	Vehicle Type and Capacity	Maximum Weight of Vehicle (tons)	Maximum Weight of Load (tons)	Maximum Weight of Vehicle and Load (tons/trip)	Maximum one-way trips per day (trip/day)	Maximum one-way distance (feet/trip)
Wastewater Treatment Biosludge Loading	Truck	20	20	40	1.0	1640
Employee Cars	Truck	20	20	40	112.0	656

4. Type, Quantity, and Characteristics of Material Handled:

Material	Maximum Throughput (tons/hour)	Maximum Pile Size (acres)	Silt Content (wt %)	Moisture Content (wt %)
Coal	5000 (Rail Unloading)	Each of the two coal storage dome enclosures has 1.62 acre footprint (i.e., 300 ft diameter at its dome base)	Not Applicable	8%
Limestone	Not Applicable			
Sand	Not Applicable			
RAP	Not Applicable			
Gravel	Not Applicable			
Slag	Not Applicable			

5. Fugitive Dust Control Measures:

(a) Fugitive particulate matter (dust) emissions from paved roads and parking lots shall be controlled by one or more of the following measures on an as needed basis:

(1) Paved roads and parking lots:

(A) cleaning by vacuum sweeping on an as needed basis;
(B) flushing on an as needed basis; and/or
(C) power brooming while wet either from rain or application of water on an as needed basis.

6. Schedule of Compliance:

This plan will be fully implemented upon startup of operations and adherence to the plan will continue until revisions to the plan have been approved by IDEM.

7. Monitoring and Record Keeping:

Records shall be kept to show compliance with each of the above listed control measures and control practices. This record shall include the date of all vacuum sweeping, wet sweeping, water flushing, spill control activities, as well dust suppressant application and the amount of suppressant applied. All records shall be kept for a minimum of three (3) years and shall be available for inspection or copying upon reasonable prior notice.

Additionally, a quarterly report shall be submitted to the department stating the following:

(a) The dates any required control measures were not implemented.

(b) A listing of those control measures.

(c) The reasons that the control measures were not implemented.

(d) Any corrective action taken.

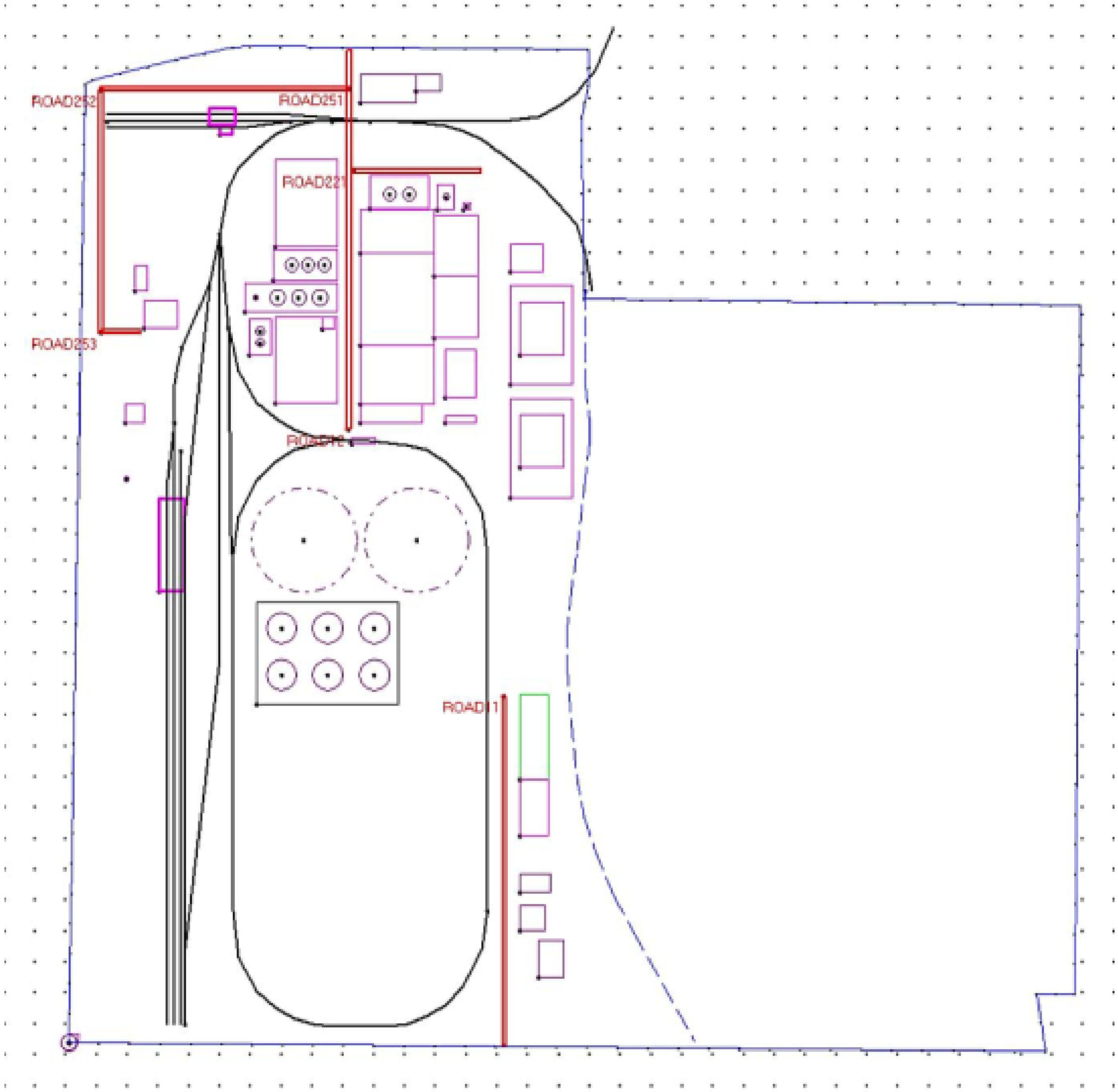
This report shall be submitted to the department thirty (30) calendar days from the end of a quarter.

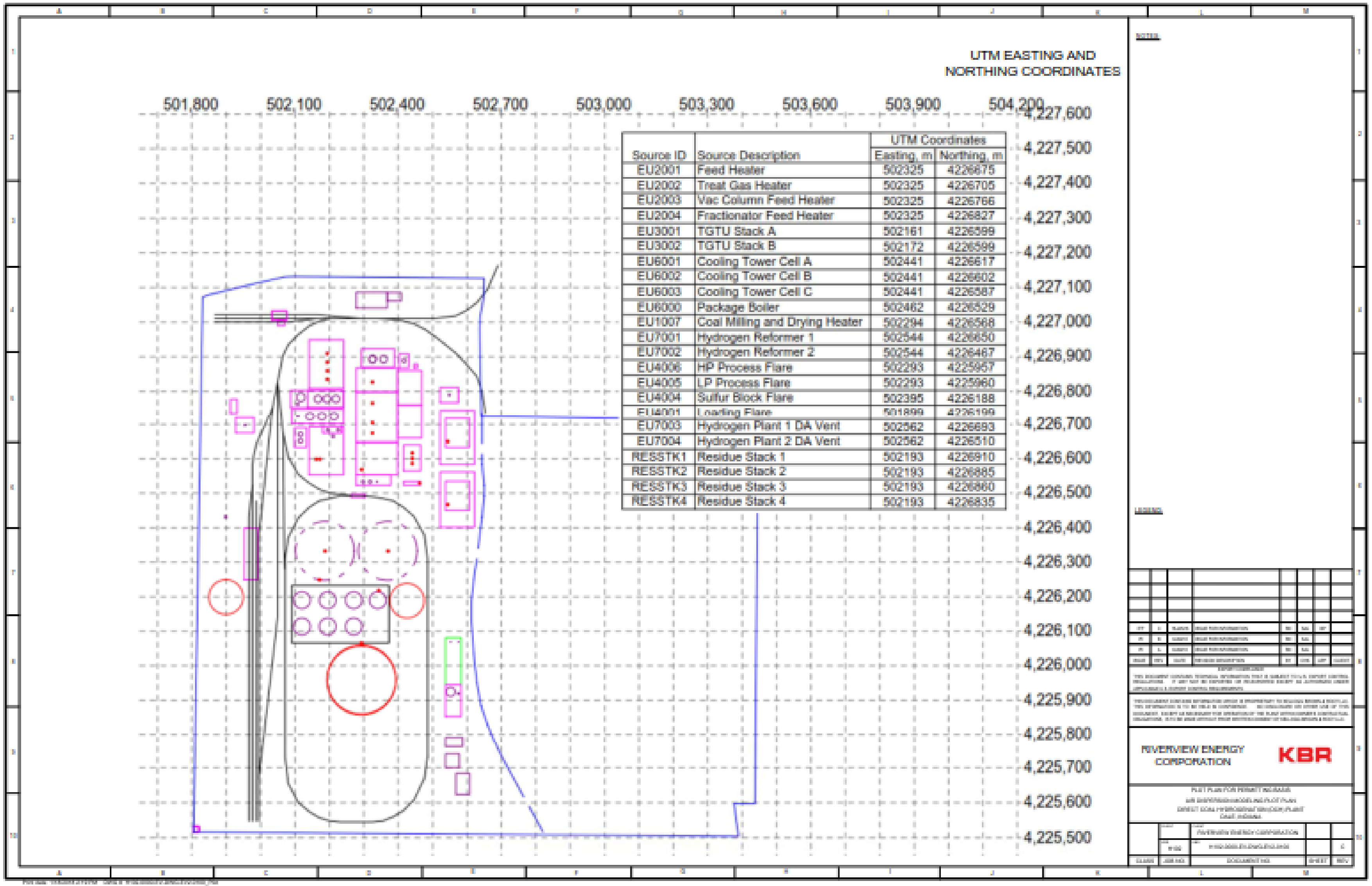
8. Map of Source Showing Location of Fugitive Dust Sources and Pollution Control Equipment:

See following plot plan from Page 206 of 209 of 25Jan18 Air Permit Application pdf file which shows point sources.

There are no portable sources of fugitive dust at the Riverview facility. In the event that portable sources are to be employed, this plan shall be amended as needed.

See also following plot plan showing roadways involved with significant vehicular traffic from materials transportation into and from site as used in air dispersion modeling analyses per quantitifaction in Section 3 above.





Source ID	Source Description	UTM Coordinates	
		Easting, m	Northing, m
EU2001	Feed Heater	502325	4226675
EU2002	Treat Gas Heater	502325	4226705
EU2003	Vac Column Feed Heater	502325	4226766
EU2004	Fractionator Feed Heater	502325	4226827
EU3001	TGTU Stack A	502161	4226599
EU3002	TGTU Stack B	502172	4226599
EU6001	Cooling Tower Cell A	502441	4226617
EU6002	Cooling Tower Cell B	502441	4226602
EU6003	Cooling Tower Cell C	502441	4226587
EU6000	Package Boiler	502462	4226529
EU1007	Coal Milling and Drying Heater	502294	4226568
EU7001	Hydrogen Reformer 1	502544	4226650
EU7002	Hydrogen Reformer 2	502544	4226467
EU4006	HP Process Flare	502293	4225957
EU4005	LP Process Flare	502293	4225960
EU4004	Sulfur Block Flare	502395	4226188
EU4001	Loading Flare	501899	4226199
EU7003	Hydrogen Plant 1 DA Vent	502562	4226693
EU7004	Hydrogen Plant 2 DA Vent	502562	4226510
RESSTK1	Residue Stack 1	502193	4226910
RESSTK2	Residue Stack 2	502193	4226885
RESSTK3	Residue Stack 3	502193	4226860
RESSTK4	Residue Stack 4	502193	4226835

Attachment B

Part 70 Operating Permit No: 147-39554-00065

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Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

Source: 72 FR 32742, June 13, 2007, unless otherwise noted.

§60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides (NO_X) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are subject to the PM and NO_X standards under this subpart and to the sulfur dioxide (SO_2) standards under subpart D (§60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NO_X standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are also subject to the NO_X standards under this subpart and the PM and SO_2 standards under subpart D (§60.42 and §60.43).

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

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; §60.50) are subject to the NO_X and PM standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

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

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

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

(i) Affected facilities (*i.e.,* heat recovery steam generators) that are associated with stationary combustion turbines and that 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 affected facilities (*i.e.* heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility (*i.e.* 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 stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

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

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO_2 and NO_X standards under this subpart and the PM standards under subpart BB.

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

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§60.41b 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 the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state 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 in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO_2) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

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

Coal refuse means any byproduct 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 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration, also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

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

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

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see §60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see §60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see §60.17).

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

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

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

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

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

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.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Gaseous fuel means any fuel that is a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).

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 gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

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

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3).

ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

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

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

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

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

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

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

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical SO_2 emissions (ng/J or lb/MMBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion 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.

Pulp and paper mills means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

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

Temporary boiler means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

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

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

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

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

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

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

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§60.42b Standard for sulfur dioxide (SO2).

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and the emission limit determined according to the following formula:

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

Where:

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

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

K_b = 340 ng/J (or 0.80 lb/MMBtu);

H_a = Heat input from the combustion of coal, in J (MMBtu); and

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

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable. For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(c) On and after the date on which the performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO_2 emissions, shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 50 percent of the potential SO_2 emission rate (50 percent reduction) and that contain SO_2 in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

Where:

E_s = SO2 emission limit, in ng/J or lb/MM Btu heat input;

K_c = 260 ng/J (or 0.60 lb/MMBtu);

K_d = 170 ng/J (or 0.40 lb/MMBtu);

H_c = Heat input from the combustion of coal, in J (MMBtu); and

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

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section. For facilities complying with paragraphs (d)(1), (2), or (3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

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

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from

combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section and §60.45b(a), the SO_2 emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential SO_2 emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO_2 emissions and

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

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO_2 control system is not being operated because of malfunction or maintenance of the SO_2 control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in §60.45b(c) or §60.45b(d), and following the monitoring procedures as described in §60.47b(a) or §60.47b(b) to determine SO_2 emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in §60.49b(r).

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2 emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. For facilities complying with the percent reduction standard and paragraph (k)(3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(2) Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in paragraph (k)(1) of this section.

(3) Units that are located in a noncontinental area and that combust coal, oil, or natural gas shall not discharge any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil or natural gas.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

§60.43b Standard for particulate matter (PM).

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

(1) 22 ng/J (0.051 lb/MMBtu) heat input, (i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

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

(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO_2 emissions is not subject to the PM limits under §60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO_2 emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

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

(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

(i) If the affected facility combusts only municipal-type solid waste; or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and

(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere 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. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is exempt from the opacity standard specified in this paragraph.

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

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,

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

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

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

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

(6) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.5 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§60.44b Standard for nitrogen oxides (NOX).

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the following emission limits:

	Nitrogen oxide emission limits (expressed as NO_2) heat input	
Fuel/steam generating unit type	**ng/J**	**lb/MMBTu**
(1) Natural gas and distillate oil, except (4):		
(i) Low heat release rate	43	0.10
(ii) High heat release rate	86	0.20
(2) Residual oil:		
(i) Low heat release rate	130	0.30
(ii) High heat release rate	170	0.40
(3) Coal:		
(i) Mass-feed stoker	210	0.50

	Nitrogen oxide emission limits (expressed as NO_2) heat input	
Fuel/steam generating unit type	**ng/J**	**lb/MMBTu**
(ii) Spreader stoker and fluidized bed combustion	260	0.60
(iii) Pulverized coal	300	0.70
(iv) Lignite, except (v)	260	0.60
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	340	0.80
(vi) Coal-derived synthetic fuels	210	0.50
(4) Duct burner used in a combined cycle system:		
(i) Natural gas and distillate oil	86	0.20
(ii) Residual oil	170	0.40

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of a limit determined by the use of the following formula:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n = NO_X emission limit (expressed as NO_2), ng/J (lb/MMBtu);

EL_{go} = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

H_{go} = Heat input from combustion of natural gas or distillate oil, J (MMBtu);

EL_{ro} = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);

H_{ro} = Heat input from combustion of residual oil, J (MMBtu);

EL_c = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c = Heat input from combustion of coal, J (MMBtu).

(c) Except as provided under paragraph (d) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, natural gas (or any combination of the three), and wood, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit for the coal, oil, natural gas (or any combination of the three), combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section. This standard does not apply to an affected facility that is subject to and in compliance with a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, natural gas (or any combination of the three).

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas and/or distillate oil with a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts only coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NO_X emission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as NO_X emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NO_X emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in §60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NO_X emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NO_X emission limit will be established at the NO_X emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NO_X emissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_X limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the NO_X emission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NO_X emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the NO_X emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the NO_X emission limits of this section. The NO_X emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_X limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the NO_X standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NO_X emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under 60.8, whichever date is first, no owner or operator of an affected facility that commenced construction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO2) in excess of the following limits:

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas (or any combination of the three); or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

E_n = NO_X emission limit, (lb/MMBtu);

H_{go} = 30-day heat input from combustion of natural gas or distillate oil; and

H_r = 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i) of

subpart Da of this part, and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of this part.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO_2 emission standards in §60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil are allowed to exceed the limit 30 operating days per calendar year for SO_2 control system maintenance.

(b) In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). 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.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO_2 emission rate (% P_s) and the SO_2 emission rate (E_s) pursuant to §60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO_2 standards 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 affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A-7 of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS of §60.47b(a) or (b).

(ii) The percent of potential SO_2 emission rate (%P_s) emitted to the atmosphere is computed using the following formula:

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

Where:

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

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

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

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

(i) An adjusted hourly SO_2 emission rate (E_{ho}^o) is used in Equation 19-19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate (E_{ao}^o). The Eho° is computed using the following formula:

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

Where:

E_{ho}^{o} = Adjusted hourly SO_2 emission rate, ng/J (lb/MMBtu);

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

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted; and

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

(ii) To compute the percent of potential SO_2 emission rate (%P_s), an adjusted %R_g (%R_g^{o}) is computed from the adjusted E_{ao}^{o} from paragraph (b)(3)(i) of this section and an adjusted average SO_2 inlet rate (E_{ai}^{o}) using the following formula:

$$\%R_g^{o} = 100\left(1.0 - \frac{E_{ao}^{o}}{E_{ai}^{o}}\right)$$

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

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

Where:

E_{hi}^{o} = Adjusted hourly SO_2 inlet rate, ng/J (lb/MMBtu); and

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

(4) The owner or operator of an affected facility subject to paragraph (c)(3) of this section does not have to measure parameters E_w or X_k if the owner or operator elects to assume that X_k = 1.0. Owners or operators of affected facilities who assume X_k = 1.0 shall:

(i) Determine %P_s following the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with SO_2 emission limits under §60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of §60.42b(d) does not have to measure parameters E_w or X_k in paragraph (c)(3) of this section if the owner or operator of the affected facility elects to measure SO_2 emission rates of the coal or oil following the fuel sampling and analysis procedures in Method 19 of appendix A-7 of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, natural gas, or a mixture of these fuels, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily

average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to §60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under §60.8, compliance with the SO_2 emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for SO_2 for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

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

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraph (c), of this section whether or not the minimum emissions data requirements under §60.46b are achieved. All valid emissions data, including valid SO_2 emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating $\%P_s$ and E_{ho} pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the SO_2 control systems when oil is combusted as provided under §60.42b(i), emission data are not used to calculate $\%P_s$ or E_s under §60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under §60.42b(i).

(j) The owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO_2 standard is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance in §§60.42b(d)(4), 60.42b(j), 60.42b(k)(2), and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures in §60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_X emission standards under §60.44b apply at all times.

(b) Compliance with the PM emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_X emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

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

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

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen (O_2) or CO_2 sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

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

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NO_X required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NO_X under §60.48(b).

(1) For the initial compliance test, NO_X from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_X emission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed in §60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal (except as specified under §60.46b(e)(4)) or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_X emission standards in §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated for each steam

generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_X standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards in §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in §60.49b(e), the requirements of §60.48b(g)(1) apply and the provisions of §60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for NO_X required by §60.44b(a)(4) or §60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under §60.8 as follows:

(i) The emissions rate (E) of NO_X shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)\left(E_{sg} - E_g\right) \qquad \text{(Eq.1)}$$

Where:

E = Emissions rate of NO_X from the duct burner, ng/J (lb/MMBtu) heat input;

E_{sg} = Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

H_g = Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

H_b = Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

E_g = Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part or Method 320 of appendix A of part 63 shall be used to determine the NO_X concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2 concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under §60.44b(a)(4) or §60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under §60.48b for measuring NO_X and O_2 and meet the requirements of §60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_X emissions rate at the outlet from the steam generating unit shall constitute the NO_X emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method or the heat input method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see §60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of §60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of §60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_X emission standards under §60.44b using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63 of this chapter, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_X emission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the PM limit in paragraphs §60.43b(a)(4) or §60.43b(h)(5) shall follow the applicable procedures in §60.49b(r).

(j) In place of PM testing with Method 5 or 5B of appendix A-3 of this part, or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(14) of this section.

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

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

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

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

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS

specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(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 (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

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

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) For O_2 (or CO_2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

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

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

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in §60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012; 79 FR 11249, Feb. 27, 2014]

§60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2 standards in §60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO_2 and either O_2 or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2 control device. If the owner or operator has installed and certified SO_2 and O_2 or CO_2 CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously; and

(2) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of §60.49b are met. SO_2 and CO_2 (or O_2) data used to meet the requirements of §60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2 data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate, or

(2) Measuring SO_2 according to Method 6B of appendix A of this part at the inlet or outlet to the SO_2 control system. An initial stratification test is required to verify the adequacy of the sampling location for Method 6B of appendix A of this part. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in Section 3.2 and the applicable procedures in Section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C or Method 320 of appendix A of part 63 of this chapter and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part, 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily SO_2 emission rate, E_D, shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A-8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19-20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler 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 or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO_2 emission rates measured by the CEMS required by paragraph (a) of this section and required under §60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under §60.42(b). Each 1-hour average SO_2 emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to §60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

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

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO_2 CEMS at the inlet to the SO_2 control device is 125 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2 control device is 50 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted. Alternatively, SO_2 span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required CO_2 and O_2 monitors and for SO_2 and NO_X monitors with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part.

(ii) For all required CO_2 and O_2 monitors and for SO_2 and NO_X monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for SO_2 and NO_X span values less than or equal to 30 ppm; and

(iii) For SO_2, CO_2, and O_2 monitoring systems and for NO_X emission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2 (regardless of the SO_2 emission level during the RATA), and for NO_X when the average NO_X emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under §60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in §60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009; 79 FR 11249, Feb. 27, 2014]

§60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under §60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

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

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

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

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.*, 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in §60.46d(d)(7).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

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

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_X standard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_X and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_X emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49b. Data reported to meet the requirements of §60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average NO_X emission rates measured by the continuous NO_X monitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a COMS shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_X is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_X span values shall be determined as follows:

Fuel	**Span values for NO_X (ppm)**
Natural gas	500.
Oil	500.
Coal	1,000.
Mixtures	500 (x + y) + 1,000z.

Where:

x = Fraction of total heat input derived from natural gas;

y = Fraction of total heat input derived from oil; and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict NO_X emission rates as specified in a plan submitted pursuant to §60.49b(c).

(h) The owner or operator of a duct burner, as described in §60.41b, that is subject to the NO_X standards in §60.44b(a)(4), §60.44b(e), or §60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_X emissions.

(i) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a CEMS for measuring NO_X emissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2 or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under §60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO_2 or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section; or

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section §60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section §60.48Da of this part; or

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in §60.46b(j). The CEMS specified in paragraph §60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(l) An owner or operator of an affected facility that is subject to an opacity standard under §60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under §60.49b(h).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012]

§60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the 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 §§60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

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

(4) Notification that an emerging technology will be used for controlling emissions of $SO_{2.}$ The Administrator will examine the description of the emerging technology 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 §60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2, PM, and/or NO_X emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the NO_X standard in §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions in the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in §60.48b(g)(2) and the records to be maintained in §60.49b(g). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. An affected facility burning coke oven gas alone or in combination with other gaseous fuels or distillate oil shall submit this plan to the Administrator for approval within 360 days of the initial startup of the affected facility or by November 30, 2009, whichever date comes later. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_X emission rates (*i.e.*, ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.*, the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.*, flue gas O_2 level);

(2) Include the data and information that the owner or operator used to identify the relationship between NO_X emission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(g).

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil,

natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(2) As an alternative to meeting the requirements of paragraph (d)(1) of this section, the owner or operator of an affected facility that is subject to a federally enforceable permit restricting fuel use to a single fuel such that the facility is not required to continuously monitor any emissions (excluding opacity) or parameters indicative of emissions may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see §60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For an affected facility subject to the opacity standard in §60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in §60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_X standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_X emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in §60.43b(f) or to the operating parameter monitoring requirements in §60.13(i)(1).

(2) Any affected facility that is subject to the NO_X standard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2 standards under §60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO_2 control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

(3) Each 30-day average percent reduction in SO_2 emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(7) Identification of times when hourly averages have been obtained based on manual sampling methods;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO_2 emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which $S0_2$ or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the

RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2 standards in §60.42(b) for which the minimum amount of data required in §60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment (*i.e.*, $\%R_f$) is used to determine the overall percent reduction (*i.e.*, $\%R_o$) under §60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (*i.e.*, $\%R_f$) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in §60.44b(j), the results of any NO_X emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_X emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in §60.42b(j) or §60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NO_X standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions.*

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring.* (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b(i).

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_X standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions.*

Air ratio control damper is defined as the part of the low NO_X burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides.* (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_X technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_X emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NO_X standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides.* (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(y) Facility-specific NO_X standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO_X.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO_X emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO_X.* (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

Attachment C

Part 70 Operating Permit No: 147-39554-00065

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Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

§ 60.40c Applicability and delegation of authority.

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

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

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

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

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

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

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

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

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

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

§ 60.41c Definitions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Natural gas means:

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

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

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

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

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

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

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

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

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

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

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

(1) The equipment is attached to a foundation.

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

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

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

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

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

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

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

§ 60.42c Standard for sulfur dioxide (SO2).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

§ 60.43c Standard for particulate matter (PM).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

$$E_{ho}o = \frac{E_{ho} - E_{w}(1 - X_{1})}{X_{1}}$$

Where:

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

Where:

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

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

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

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

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

(8) Method 9 of appendix A-4 of this part shall be used for determining the opacity of stack emissions.

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

(c) In place of PM testing with Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

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

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

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

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

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

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

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

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

(ii) [Reserved]

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

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

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) For O2 (or CO_2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

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

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

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under § 60.43c(e)(4) shall follow the applicable procedures under § 60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2 emission limits under § 60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations at the outlet of the SO_2 control device (or the outlet of the steam generating unit if no SO_2 control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under § 60.42c shall measure SO_2 concentrations and either O_2 or CO_2 concentrations at both the inlet and outlet of the SO_2 control device.

(b) The 1-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.42c. Each 1-hour average SO_2 emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under § 60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

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

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

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

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

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

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

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

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

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

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in § 3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to § 60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under § 60.48c(f), as applicable.

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

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

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

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

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

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in § 60.45c(a)(8).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

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

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

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO2 or PM emissions and that are subject to an opacity standard in § 60.43c(c) are not required to operate a COMS if they follow the applicable procedures in § 60.48c(f).

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

(e) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2 , or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.48c Reporting and recordkeeping requirements.

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

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

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

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

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2 emission limits of § 60.42c, or the PM or opacity limits of § 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO_2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

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

(1) For distillate oil:

(i) The name of the oil supplier;

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

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

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

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

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

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in § 60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in § 60.42C to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under § 60.42c or § 60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

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

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

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

Attachment D

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on July 19, 2016]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart Ja—Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

Source: 73 FR 35867, June 24, 2008, unless otherwise noted.

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

(a) The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants. The 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) Except for flares and delayed coking units, the provisions of this subpart apply only to affected facilities under paragraph (a) of this section which either commence construction, modification or reconstruction after May 14, 2007, or elect to comply with the provisions of this subpart in lieu of complying with the provisions in subpart J of this part. For flares, the provisions of this subpart apply only to flares which commence construction, modification or reconstruction after June 24, 2008. For the purposes of this subpart, a modification to a flare commences when a project that includes any of the activities in paragraphs (c)(1) or (2) of this section is commenced. For delayed coking units, the provisions of this subpart apply to delayed coking units that commence construction, reconstruction or modification on the earliest of the following dates:

(1) May 14, 2007, for such activities that involve a “delayed coking unit” defined as follows: one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors;

(2) December 22, 2008, for such activities that involve a “delayed coking unit” defined as follows: a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A delayed coking unit consists of the coke drums and associated fractionator;

(3) September 12, 2012, for such activities that involve a “delayed coking unit” as defined in §60.101a.

(c) For all affected facilities other than flares, the provisions in §60.14 regarding modification apply. As provided in §60.14(f), the special provisions set forth under this subpart shall supersede the provisions in §60.14 with respect to flares. For the purposes of this subpart, a modification to a flare occurs as provided in paragraphs (c)(1) or (2) of this section.

(1) Any new piping from a refinery process unit, including ancillary equipment, or a fuel gas system is physically connected to the flare (*e.g.,* for direct emergency relief or some form of continuous or intermittent venting). However, the connections described in paragraphs (c)(1)(i) through (vii) of this section are not considered modifications of a flare.

(i) Connections made to install monitoring systems to the flare.

(ii) Connections made to install a flare gas recovery system or connections made to upgrade or enhance components of a flare gas recovery system (*e.g.,* addition of compressors or recycle lines).

(iii) Connections made to replace or upgrade existing pressure relief or safety valves, provided the new pressure relief or safety valve has a set point opening pressure no lower and an internal diameter no greater than the existing equipment being replaced or upgraded.

(iv) Connections made for flare gas sulfur removal.

(v) Connections made to install back-up (redundant) equipment associated with the flare (such as a back-up compressor) that does not increase the capacity of the flare.

(vi) Replacing piping or moving an existing connection from a refinery process unit to a new location in the same flare, provided the new pipe diameter is less than or equal to the diameter of the pipe/connection being replaced/moved.

(vii) Connections that interconnect two or more flares.

(2) A flare is physically altered to increase the flow capacity of the flare.

(d) 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 the relevant applicability date specified in paragraph (b) of this section.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56464, Sep. 12, 2012; 80 FR 75230, Dec. 1, 2015]

§60.101a Definitions.

Terms used in this subpart are defined in the Clean Air Act (CAA), in §60.2 and in this section.

Air preheat means a device used to heat the air supplied to a process heater generally by use of a heat exchanger to recover the sensible heat of exhaust gas from the process heater.

Ancillary equipment means equipment used in conjunction with or that serve a refinery process unit. *Ancillary equipment* includes, but is not limited to, storage tanks, product loading operations, wastewater treatment systems, steam- or electricity-producing units (including coke gasification units), pressure relief valves, pumps, sampling vents and continuous analyzer vents.

Cascaded flare system means a series of flares connected to one flare gas header system arranged with increasing pressure set points so that discharges will be initially directed to the first flare in the series (*i.e.,* the primary flare). If the discharge pressure exceeds a set point at which the flow to the primary flare would exceed the primary flare's capacity, flow will be diverted to the second flare in the series. Similarly, flow would be diverted to a third (or fourth) flare if the pressure in the flare gas header system exceeds a threshold where the flow to the first two (or three) flares would exceed their capacities.

Co-fired process heater means a process heater that employs burners that are designed to be supplied by both gaseous and liquid fuels on a routine basis. Process heaters that have gas burners with emergency oil back-up burners are not considered co-fired process heaters.

Coke burn-off means the coke removed from the surface of the FCCU catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in §60.104a.

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

Corrective action means the design, operation and maintenance changes that one takes consistent with good engineering practice to reduce or eliminate the likelihood of the recurrence of the primary cause and any other contributing cause(s) of an event identified by a root cause analysis as having resulted in a discharge of gases from an affected facility in excess of specified thresholds.

Corrective action analysis means a description of all reasonable interim and long-term measures, if any, that are available, and an explanation of why the selected corrective action(s) is/are the best alternative(s), including, but not limited to, considerations of cost effectiveness, technical feasibility, safety and secondary impacts.

Delayed coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A *delayed coking unit* includes, but is not limited to, all of the coke drums associated with a single fractionator; the fractionator, including the bottoms receiver and the overhead condenser; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; and the coke drum blowdown recovery compressor system.

Emergency flare means a flare that combusts gas exclusively released as a result of malfunctions (and not startup, shutdown, routine operations or any other cause) on four or fewer occasions in a rolling 365-day period. For purposes of this rule, a flare cannot be categorized as an *emergency flare* unless it maintains a water seal.

Flare means a combustion device that uses an uncontrolled volume of air to burn gases. The *flare* includes the foundation, flare tip, structural support, burner, igniter, flare controls, including air injection or steam injection systems, flame arrestors and the flare gas header system. In the case of an interconnected flare gas header system, the *flare* includes each individual flare serviced by the interconnected flare gas header system and the interconnected flare gas header system.

Flare gas header system means all piping and knockout pots, including those in a subheader system, used to collect and transport gas to a flare either from a process unit or a pressure relief valve from the fuel gas system, regardless of whether or not a flare gas recovery system draws gas from the *flare gas header system.* The *flare gas header system* includes piping inside the battery limit of a process unit if the purpose of the piping is to transport gas to a flare or knockout pot that is part of the flare.

Flare gas recovery system means a system of one or more compressors, piping and the associated water seal, rupture disk or similar device used to divert gas from the flare and direct the gas to the fuel gas system or to a fuel gas combustion device.

Flexicoking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced and then gasified to produce a synthetic fuel gas.

Fluid catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged and 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 regenerated 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. When *fluid catalyst cracking unit* regenerator exhaust from two separate fluid catalytic cracking units share a common exhaust treatment (e.g., CO boiler or wet scrubber), the *fluid catalytic cracking unit* is a single affected facility.

Fluid coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The *fluid coking unit* includes the coking reactor, the coking burner, and equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent.

Forced draft process heater means a process heater in which the combustion air is supplied under positive pressure produced by a fan at any location in the inlet air line prior to the point where the combustion air enters the process heater or air preheat. For the purposes of this subpart, a process heater that uses fans at both the inlet air side and the exhaust air side (*i.e.,* balanced draft system) is considered to be a *forced draft process heater.*

Fuel gas means any gas which is generated at a petroleum refinery and which is combusted. *Fuel gas* 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, coke calciners (used to make premium grade coke) and fluid coking burners, but does include gases from flexicoking unit gasifiers and other gasifiers. *Fuel gas* does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units other than those processing sour water, marine tank vessel loading operations or asphalt processing units (*i.e.,* asphalt blowing stills).

Fuel gas combustion device means any equipment, such as process heaters and boilers, used to combust fuel gas. For the purposes of this subpart, *fuel gas combustion device* does not include flares or facilities in which gases are combusted to produce sulfur or sulfuric acid.

Fuel gas system means a system of compressors, piping, knock-out pots, mix drums, and units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers) that collects refinery fuel gas from one or more sources for treatment as necessary prior to combusting in process heaters or boilers. A *fuel gas system* may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the refinery.

Natural draft process heater means any process heater in which the combustion air is supplied under ambient or negative pressure without the use of an inlet air (forced draft) fan. For the purposes of this subpart, a *natural draft process heater* is any process heater that is not a forced draft process heater, including induced draft systems.

Non-emergency flare means any flare that is not an emergency flare as defined in this subpart.

Oxidation control system means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide (SO_2) and recycling the SO_2 to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the SO_2 to a sulfur product.

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

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives. A facility that produces only oil shale or tar sands-derived crude oil for further processing at a petroleum refinery using only solvent extraction and/or distillation to recover diluent is not a *petroleum refinery.*

Primary flare means the first flare in a cascaded flare system.

Process heater means an enclosed combustion device used to transfer heat indirectly to process stream materials (liquids, gases, or solids) or to a heat transfer material for use in a process unit instead of steam.

Process upset gas means any gas generated by a petroleum refinery process unit or by ancillary equipment as a result of startup, shutdown, upset or malfunction.

Purge gas means gas introduced between a flare's water seal and a flare's tip to prevent oxygen infiltration (backflow) into the flare tip. For flares with no water seals, the function of *purge gas* is performed by sweep gas (*i.e.,* flares without water seals do not use *purge gas*).

Reduced sulfur compounds means hydrogen sulfide (H_2S), carbonyl sulfide, and carbon disulfide.

Reduction control system means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to H_2S and either recycling the H_2S to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the H_2S to a sulfur product.

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

Root cause analysis means an assessment conducted through a process of investigation to determine the primary cause, and any other contributing cause(s), of a discharge of gases in excess of specified thresholds.

Secondary flare means a flare in a cascaded flare system that provides additional flare capacity and pressure relief to a flare gas system when the flare gas flow exceeds the capacity of the primary flare. For purposes of this subpart, a *secondary flare* is characterized by infrequent use and must maintain a water seal.

Sour water means water that contains sulfur compounds (usually H_2S) at concentrations of 10 parts per million by weight or more.

Sulfur pit means the storage vessel in which sulfur that is condensed after each Claus catalytic reactor is initially accumulated and stored. *A sulfur pit* does not include secondary sulfur storage vessels downstream of the initial Claus reactor sulfur pits.

Sulfur recovery plant means all process units which recover sulfur from H_2S and/or SO_2 from a common source of sour gas produced at a petroleum refinery. The *sulfur recovery plant* also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels or loading facilities downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits and, if present, oxidation or reduction control systems or incinerator, thermal oxidizer or similar combustion device. Multiple sulfur recovery units are a single affected facility only when the units share the same source of sour gas. *Sulfur recovery plants* that receive source gas from completely segregated sour gas treatment systems are separate affected facilities.

Sweep gas means the gas introduced in a flare gas header system to maintain a constant flow of gas to prevent oxygen buildup in the flare header. For flares with no water seals, *sweep gas* also performs the function of preventing oxygen infiltration (backflow) into the flare tip.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56464, Sep. 12, 2012; 78 FR 76756, Dec. 19, 2013; 80 FR 75230, Dec. 1, 2015]

§60.102a Emissions limitations.

(a) Each owner or operator that is subject to the requirements of this subpart shall comply with the emissions limitations in paragraphs (b) through (i) of 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.

(b) An owner or operator subject to the provisions of this subpart shall not discharge or cause the discharge into the atmosphere from any FCCU or FCU:

(1) Particulate matter (PM) in excess of the limits in paragraphs (b)(1)(i), (ii), or (iii) of this section.

(i) 1.0 gram per kilogram (g/kg) (1 pound (lb) per 1,000 lb) coke burn-off or, if a PM continuous emission monitoring system (CEMS) is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each modified or reconstructed FCCU.

(ii) 0.5 gram per kilogram (g/kg) coke burn-off (0.5 lb PM/1,000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air for each newly constructed FCCU.

(iii) 1.0 g/kg (1 lb/1,000 lb) coke burn-off or, if a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each affected FCU.

(2) Nitrogen oxides (NO_X) in excess of 80 parts per million by volume (ppmv), dry basis corrected to 0 percent excess air, on a 7-day rolling average basis.

(3) Sulfur dioxide (SO_2) in excess of 50 ppmv dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis.

(4) Carbon monoxide (CO) in excess of 500 ppmv, dry basis corrected to 0 percent excess air, on an hourly average basis.

(c) The owner or operator of a FCCU or FCU that uses a continuous parameter monitoring system (CPMS) according to §60.105a(b)(1) shall comply with the applicable control device parameter operating limit in paragraph (c)(1) or (2) of this section.

(1) If the FCCU or FCU is controlled using an electrostatic precipitator:

(i) The 3-hour rolling average total power and secondary current to the entire system must not fall below the level established during the most recent performance test; and

(ii) The daily average exhaust coke burn-off rate must not exceed the level established during the most recent performance test.

(2) If the FCCU or FCU is controlled using a wet scrubber:

(i) The 3-hour rolling average pressure drop must not fall below the level established during the most recent performance test; and

(ii) The 3-hour rolling average liquid-to-gas ratio must not fall below the level established during the most recent performance test.

(d) If an FCCU or FCU uses a continuous opacity monitoring system (COMS) according to the alternative monitoring option in §60.105a(e), the 3-hour rolling average opacity of emissions from the FCCU or FCU as measured by the COMS must not exceed the site-specific opacity limit established during the most recent performance test.

(e) The owner or operator of a FCCU or FCU that is exempted from the requirement for a CO continuous emissions monitoring system under §60.105a(h)(3) shall comply with the parameter operating limits in paragraph (e)(1) or (2) of this section.

(1) For a FCCU or FCU with no post-combustion control device:

(i) The hourly average temperature of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(ii) The hourly average oxygen (O_2) concentration of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(2) For a FCCU or FCU with a post-combustion control device:

(i) The hourly average temperature of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(ii) The hourly average O_2 concentration of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(f) Except as provided in paragraph (f)(3) of this section, each owner or operator of an affected sulfur recovery plant shall comply with the applicable emission limits in paragraph (f)(1) or (2) of this section.

(1) For a sulfur recovery plant with a design production capacity greater than 20 long tons per day (LTD), the owner or operator shall comply with the applicable emission limit in paragraph (f)(1)(i) or (ii) of this section. If the sulfur recovery plant consists of multiple process trains or release points, the owner or operator shall comply with the applicable emission limit for each process train or release point individually or comply with the applicable emission limit in paragraph (f)(1)(i) or (ii) as a flow rate weighted average for a group of release points from the sulfur recovery plant provided that flow is monitored as specified in §60.106a(a)(7); if flow is not monitored as specified in

§60.106a(a)(7), the owner or operator shall comply with the applicable emission limit in paragraph (f)(1)(i) or (ii) for each process train or release point individually. For a sulfur recovery plant with a design production capacity greater than 20 long LTD and a reduction control system not followed by incineration, the owner or operator shall also comply with the H_2S emission limit in paragraph (f)(1)(iii) of this section for each individual release point.

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases containing SO_2 into the atmosphere in excess of the emission limit calculated using Equation 1 of this section. For Claus units that use only ambient air in the Claus burner or that elect not to monitor O_2 concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, this SO_2 emissions limit is 250 ppmv (dry basis) at zero percent excess air.

$$E_{LS} = k_1 \times \left(-0.038 \times (\%O_2)^2 + 11.53 \times \%O_2 + 25.6\right) \qquad \text{(Eq. 1)}$$

Where:

E_{LS} = Emission limit for large sulfur recovery plant, ppmv (as SO_2, dry basis at zero percent excess air);

k_1 = Constant factor for emission limit conversion: $k_1 = 1$ for converting to the SO_2 limit for a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration and $k_1 = 1.2$ for converting to the reduced sulfur compounds limit for a sulfur recovery plant with a reduction control system not followed by incineration; and

$\%O_2$ = O_2 concentration of the air/oxygen mixture supplied to the Claus burner, percent by volume (dry basis). If only ambient air is used for the Claus burner or if the owner or operator elects not to monitor O_2 concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, use 20.9% for $\%O_2$.

(ii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing reduced sulfur compounds in excess of the emission limit calculated using Equation 1 of this section. For Claus units that use only ambient air in the Claus burner or for non-Claus sulfur recovery plants, this reduced sulfur compounds emission limit is 300 ppmv calculated as ppmv SO_2 (dry basis) at 0-percent excess air.

(iii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing hydrogen sulfide (H_2S) in excess of 10 ppmv calculated as ppmv SO_2 (dry basis) at zero percent excess air.

(2) For a sulfur recovery plant with a design production capacity of 20 LTD or less, the owner or operator shall comply with the applicable emission limit in paragraph (f)(2)(i) or (ii) of this section. If the sulfur recovery plant consists of multiple process trains or release points, the owner or operator may comply with the applicable emission limit for each process train or release point individually or comply with the applicable emission limit in paragraph (f)(2)(i) or (ii) as a flow rate weighted average for a group of release points from the sulfur recovery plant provided that flow is monitored as specified in §60.106a(a)(7); if flow is not monitored as specified in §60.106a(a)(7), the owner or operator shall comply with the applicable emission limit in paragraph (f)(2)(i) or (ii) for each process train or release point individually. For a sulfur recovery plant with a design production capacity of 20 LTD or less and a reduction control system not followed by incineration, the owner or operator shall also comply with the H_2S emission limit in paragraph (f)(2)(iii) of this section for each individual release point.

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing SO_2 in excess of the emission limit calculated using Equation 2 of this section. For Claus units that use only ambient air in the Claus burner or that elect not to monitor O_2 concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, this SO_2 emission limit is 2,500 ppmv (dry basis) at zero percent excess air.

$$E_{SS} = k_1 \times \left(-0.38 \times (\%O_2)^2 + 115.3 \times \%O_2 + 256\right) \qquad \text{(Eq. 2)}$$

Where:

E_{SS} = Emission limit for small sulfur recovery plant, ppmv (as SO_2, dry basis at zero percent excess air);

k_1 = Constant factor for emission limit conversion: $k_1 = 1$ for converting to the SO_2 limit for a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration and $k_1 = 1.2$ for converting to the reduced sulfur compounds limit for a sulfur recovery plant with a reduction control system not followed by incineration; and

$\%O_2$ = O_2 concentration of the air/oxygen mixture supplied to the Claus burner, percent by volume (dry basis). If only ambient air is used in the Claus burner or if the owner or operator elects not to monitor O_2 concentration of the air/oxygen mixture used in the Claus burner or for non-Claus sulfur recovery plants, use 20.9% for $\%O_2$.

(ii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing reduced sulfur compounds in excess of the emission limit calculated using Equation 2 of this section. For Claus units that use only ambient air in the Claus burner or for non-Claus sulfur recovery plants, this reduced sulfur compounds emission limit is 3,000 ppmv calculated as ppmv SO_2 (dry basis) at zero percent excess air.

(iii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere containing H_2S in excess of 100 ppmv calculated as ppmv SO_2 (dry basis) at zero percent excess air.

(3) The emission limits in paragraphs (f)(1) and (2) of this section shall not apply during periods of maintenance of the sulfur pit, which shall not exceed 240 hours per year. The owner or operator must document the time periods during which the sulfur pit vents were not controlled and measures taken to minimize emissions during these periods. Examples of these measures include not adding fresh sulfur or shutting off vent fans.

(g) Each owner or operator of an affected fuel gas combustion device shall comply with the emissions limits in paragraphs (g)(1) and (2) of this section.

(1) Except as provided in (g)(1)(iii) of this section, for each fuel gas combustion device, the owner or operator shall comply with either the emission limit in paragraph (g)(1)(i) of this section or the fuel gas concentration limit in paragraph (g)(1)(ii) of this section. For CO boilers or furnaces that are part of a fluid catalytic cracking unit or fluid coking unit affected facility, the owner or operator shall comply with the fuel gas concentration limit in paragraph (g)(1)(ii) for all fuel gas streams combusted in these units.

(i) The owner or operator shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling average basis and SO_2 in excess of 8 ppmv (dry basis, corrected to 0-percent excess air), determined daily on a 365 successive calendar day rolling average basis; or

(ii) The owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

(iii) The combustion in a portable generator of fuel gas released as a result of tank degassing and/or cleaning is exempt from the emissions limits in paragraphs (g)(1)(i) and (ii) of this section.

(2) For each process heater with a rated capacity of greater than 40 million British thermal units per hour (MMBtu/hr) on a higher heating value basis, the owner or operator shall not discharge to the atmosphere any emissions of NO_X in excess of the applicable limits in paragraphs (g)(2)(i) through (iv) of this section.

(i) For each natural draft process heater, comply with the limit in either paragraph (g)(2)(i)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in §60.107a; if fuel gas composition is not monitored as specified in §60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(i)(A) of this section.

(A) 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.040 pounds per million British thermal units (lb/MMBtu) higher heating value basis determined daily on a 30-day rolling average basis.

(ii) For each forced draft process heater, comply with the limit in either paragraph (g)(2)(ii)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in §60.107a; if fuel gas composition is not monitored as specified in §60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(ii)(A) of this section.

(A) 60 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.060 lb/MMBtu higher heating value basis determined daily on a 30-day rolling average basis.

(iii) For each co-fired natural draft process heater, comply with the limit in either paragraph (g)(2)(iii)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

(B) The daily average emissions limit calculated using Equation 3 of this section:

$$ER_{NOx} = \frac{0.06\,Q_{gas}\,HHV_{gas} + 0.35\,Q_{oil}\,HHV_{oil}}{Q_{gas}\,HHV_{gas} + Q_{oil}\,HHV_{oil}} \qquad \text{(Eq. 3)}$$

Where:

ER_{NOx} = Daily allowable average emission rate of NO_X, lb/MMBtu (higher heating value basis);

Q_{gas} = Daily average volumetric flow rate of fuel gas, standard cubic feet per day (scf/day);

Q_{oil} = Daily average volumetric flow rate of fuel oil, scf/day;

HHV_{gas} = Daily average higher heating value of gas fired to the process heater, MMBtu/scf; and

HHV_{oil} = Daily average higher heating value of fuel oil fired to the process heater, MMBtu/scf.

(iv) For each co-fired forced draft process heater, comply with the limit in either paragraph (g)(2)(iv)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

(B) The daily average emissions limit calculated using Equation 4 of this section:

$$ER_{NOx} = \frac{0.11\,Q_{gas}\,HHV_{gas} + 0.40\,Q_{oil}\,HHV_{oil}}{Q_{gas}\,HHV_{gas} + Q_{oil}\,HHV_{oil}} \qquad \text{(Eq. 4)}$$

Where:

ER_{NOx} = Daily allowable average emission rate of NO_X, lb/MMBtu (higher heating value basis);

Q_{gas} = Daily average volumetric flow rate of fuel gas, scf/day;

Q_{oil} = Daily average volumetric flow rate of fuel oil, scf/day;

HHV_{gas} = Daily average higher heating value of gas fired to the process heater, MMBtu/scf; and

HHV_{oil} = Daily average higher heating value of fuel oil fired to the process heater, MMBtu/scf.

(h) [Reserved]

(i) For a process heater that meets any of the criteria of paragraphs (i)(1)(i) through (iv) of this section, an owner or operator may request approval from the Administrator for a NO_X emissions limit which shall apply specifically to that affected facility. The request shall include information as described in paragraph (i)(2) of this section. The request shall be submitted and followed as described in paragraph (i)(3) of this section.

(1) A process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may apply for a site-specific NO_X emissions limit:

(i) A modified or reconstructed process heater that lacks sufficient space to accommodate installation and proper operation of combustion modification-based technology (e.g., ultra-low NO_X burners); or

(ii) A modified or reconstructed process heater that has downwardly firing induced draft burners; or

(iii) A co-fired process heater; or

(iv) A process heater operating at reduced firing conditions for an extended period of time (*i.e.,* operating in turndown mode). The site-specific NO_X emissions limit will only apply for those operating conditions.

(2) The request shall include sufficient and appropriate data, as determined by the Administrator, to allow the Administrator to confirm that the process heater is unable to comply with the applicable NO_X emissions limit in paragraph (g)(2) of this section. At a minimum, the request shall contain the information described in paragraphs (i)(2)(i) through (iv) of this section.

(i) The design and dimensions of the process heater, evaluation of available combustion modification-based technology, description of fuel gas and, if applicable, fuel oil characteristics, information regarding the combustion conditions (temperature, oxygen content, firing rates) and other information needed to demonstrate that the process heater meets one of the four classes of process heaters listed in paragraph (i)(1) of this section.

(ii) An explanation of how the data in paragraph (i)(2)(i) demonstrate that ultra-low NO_X burners, flue gas recirculation, control of excess air or other combustion modification-based technology (including combinations of these combustion modification-based technologies) cannot be used to meet the applicable emissions limit in paragraph (g)(2) of this section.

(iii) Results of a performance test conducted under representative conditions using the applicable methods specified in §60.104a(i) to demonstrate the performance of the technology the owner or operator will use to minimize NO_X emissions.

(iv) The means by which the owner or operator will document continuous compliance with the site-specific emissions limit.

(3) The request shall be submitted and followed as described in paragraphs (i)(3)(i) through (iii) of this section.

(i) The owner or operator of a process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may request approval from the Administrator within 180 days after initial startup of the process heater for a NO_X emissions limit which shall apply specifically to that affected facility.

(ii) The request must be submitted to the Administrator for approval. The owner or operator must comply with the request as submitted until it is approved.

(iii) The request shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refinerynsps@epa.gov.*

(4) The approval process for a request for a facility-specific NO_X emissions limit is described in paragraphs (i)(4)(i) through (iii) of this section.

(i) Approval by the Administrator of a facility-specific NO_X emissions limit request will be based on the completeness, accuracy and reasonableness of the request. Factors that the EPA will consider in reviewing the request for approval include, but are not limited to, the following:

(A) A demonstration that the process heater meets one of the four classes of process heaters outlined in paragraphs (i)(1) of this section;

(B) A description of the low-NO_X burner designs and other combustion modifications considered for reducing NO_X emissions;

(C) The combustion modification option selected; and

(D) The operating conditions (firing rate, heater box temperature and excess oxygen concentration) at which the NO_X emission level was established.

(ii) If the request is approved by the Administrator, a facility-specific NO_X emissions limit will be established at the NO_X emission level demonstrated in the approved request.

(iii) If the Administrator finds any deficiencies in the request, the request must be revised to address the deficiencies and be re-submitted for approval.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56466, Sep. 12, 2012; 80 FR 75230, Dec. 1, 2015; 81 FR 45240, July 13, 2016]

§60.103a Design, equipment, work practice or operational standards.

(a) Except as provided in paragraph (g) of this section, each owner or operator that operates a flare that is subject to this subpart shall develop and implement a written flare management plan no later than the date specified in paragraph (b) of this section. The flare management plan must include the information described in paragraphs (a)(1) through (7) of this section.

(1) A listing of all refinery process units, ancillary equipment, and fuel gas systems connected to the flare for each affected flare.

(2) An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized. The flare minimization assessment must (at a minimum) consider the items in paragraphs (a)(2)(i) through (iv) of this section. The assessment must provide clear rationale in terms of costs (capital and annual operating), natural gas offset credits (if applicable), technical feasibility, secondary environmental impacts and safety considerations for the selected minimization alternative(s) or a statement, with justifications, that flow reduction could not be achieved. Based upon the assessment, each owner or operator of an affected flare shall identify the minimization alternatives that it has implemented by the due date of the flare management plan and shall include a schedule for the prompt implementation of any selected measures that cannot reasonably be completed as of that date.

(i) Elimination of process gas discharge to the flare through process operating changes or gas recovery at the source.

(ii) Reduction of the volume of process gas to the flare through process operating changes.

(iii) Installation of a flare gas recovery system or, for facilities that are fuel gas rich, a flare gas recovery system and a co-generation unit or combined heat and power unit.

(iv) Minimization of sweep gas flow rates and, for flares with water seals, purge gas flow rates.

(3) A description of each affected flare containing the information in paragraphs (a)(3)(i) through (vii) of this section.

(i) A general description of the flare, including the information in paragraphs (a)(3)(i)(A) through (G) of this section.

(A) Whether it is a ground flare or elevated (including height).

(B) The type of assist system (e.g., air, steam, pressure, non-assisted).

(C) Whether it is simple or complex flare tip (e.g., staged, sequential).

(D) Whether the flare is part of a cascaded flare system (and if so, whether the flare is primary or secondary).

(E) Whether the flare serves as a backup to another flare.

(F) Whether the flare is an emergency flare or a non-emergency flare.

(G) Whether the flare is equipped with a flare gas recovery system.

(ii) Description and simple process flow diagram showing the interconnection of the following components of the flare: flare tip (date installed, manufacturer, nominal and effective tip diameter, tip drawing); knockout or surge drum(s) or pot(s) (including dimensions and design capacities); flare header(s) and subheader(s); assist system; and ignition system.

(iii) Flare design parameters, including the maximum vent gas flow rate; minimum sweep gas flow rate; minimum purge gas flow rate (if any); maximum supplemental gas flow rate; maximum pilot gas flow rate; and, if the flare is steam-assisted, minimum total steam rate.

(iv) Description and simple process flow diagram showing all gas lines (including flare, purge (if applicable), sweep, supplemental and pilot gas) that are associated with the flare. For purge, sweep, supplemental and pilot gas, identify the type of gas used. Designate which lines are exempt from sulfur, H_2S or flow monitoring and why (e.g., natural gas, inherently low sulfur, pilot gas). Designate which lines are monitored and identify on the process flow diagram the location and type of each monitor.

(v) For each flow rate, H_2S, sulfur content, pressure or water seal monitor identified in paragraph (a)(3)(iv) of this section, provide a detailed description of the manufacturer's specifications, including, but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance and quality assurance procedures.

(vi) For emergency flares, secondary flares and flares equipped with a flare gas recovery system designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction:

(A) Description of the water seal, including the operating range for the liquid level.

(B) Designation of the monitoring option elected (flow and sulfur monitoring or pressure and water seal liquid level monitoring).

(vii) For flares equipped with a flare gas recovery system:

(A) A description of the flare gas recovery system, including number of compressors and capacity of each compressor.

(B) A description of the monitoring parameters used to quantify the amount of flare gas recovered.

(C) For systems with staged compressors, the maximum time period required to begin gas recovery with the secondary compressor(s), the monitoring parameters and procedures used to minimize the duration of releases during compressor staging and a justification for why the maximum time period cannot be further reduced.

(4) An evaluation of the baseline flow to the flare. The baseline flow to the flare must be determined after implementing the minimization assessment in paragraph (a)(2) of this section. Baseline flows do not include pilot gas flow or purge gas flow (*i.e.,* gas introduced after the flare's water seal) provided these gas flows remain reasonably constant (*i.e.,* separate flow monitors for these streams are not required). Separate baseline flow rates may be established for different operating conditions provided that the management plan includes:

(i) A primary baseline flow rate that will be used as the default baseline for all conditions except those specifically delineated in the plan;

(ii) A description of each special condition for which an alternate baseline is established, including the rationale for each alternate baseline, the daily flow for each alternate baseline and the expected duration of the special conditions for each alternate baseline; and

(iii) Procedures to minimize discharges to the affected flare during each special condition described in paragraph (a)(4)(ii) of this section, unless procedures are already developed for these cases under paragraph (a)(5) through (7) of this section, as applicable.

(5) Procedures to minimize or eliminate discharges to the flare during the planned startup and shutdown of the refinery process units and ancillary equipment that are connected to the affected flare, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(6) Procedures to reduce flaring in cases of fuel gas imbalance (*i.e.,* excess fuel gas for the refinery's energy needs), together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(7) For flares equipped with flare gas recovery systems, procedures to minimize the frequency and duration of outages of the flare gas recovery system and procedures to minimize the volume of gas flared during such outages, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(b) Except as provided in paragraph (g) of this section, each owner or operator required to develop and implement a written flare management plan as described in paragraph (a) of this section must submit the plan to the Administrator as described in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator of a newly constructed or reconstructed flare must develop and implement the flare management plan by no later than the date that the flare becomes an affected facility subject to this subpart, except for the selected minimization alternatives in paragraph (a)(2) and/or the procedures in paragraphs (a)(5) though (a)(7) of this section that cannot reasonably be implemented by that date, which the owner or operator must implement in accordance with the schedule in the flare management plan. The owner or operator of a modified flare must develop and implement the flare management plan by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(2) The owner or operator must comply with the plan as submitted by the date specified in paragraph (b)(1) of this section. The plan should be updated periodically to account for changes in the operation of the flare, such as new connections to the flare or the installation of a flare gas recovery system, but the plan need be re-submitted to the Administrator only if the owner or operator adds an alternative baseline flow rate, revises an existing baseline as described in paragraph (a)(4) of this section, installs a flare gas recovery system or is required to change flare designations and monitoring methods as described in §60.107a(g). The owner or operator must comply with the updated plan as submitted.

(3) All versions of the plan submitted to the Administrator shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refinerynsps@epa.gov.*

(c) Except as provided in paragraphs (f) and (g) of this section, each owner or operator that operates a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall conduct a root cause analysis and a corrective action analysis for each of the conditions specified in paragraphs (c)(1) through (3) of this section.

(1) For a flare:

(i) Any time the SO_2 emissions exceed 227 kilograms (kg) (500 lb) in any 24-hour period; or

(ii) Any discharge to the flare in excess of 14,160 standard cubic meters (m^3) (500,000 standard cubic feet (scf)) above the baseline, determined in paragraph (a)(4) of this section, in any 24-hour period; or

(iii) If the monitoring alternative in §60.107a(g) is elected, any period when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in paragraph (a)(3)(vii)(C) of this section.

(2) For a fuel gas combustion device, each exceedance of an applicable short-term emissions limit in §60.102a(g)(1) if the SO_2 discharge to the atmosphere is 227 kg (500 lb) greater than the amount that would have been emitted if the emissions limits had been met during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(3) For a sulfur recovery plant, each time the SO_2 emissions are more than 227 kg (500 lb) greater than the amount that would have been emitted if the SO_2 or reduced sulfur concentration was equal to the applicable emissions limit in §60.102a(f)(1) or (2) during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(d) Except as provided in paragraphs (f) and (g) of this section, a root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a discharge meeting one of the conditions specified in paragraphs (c)(1) through (3) of this section. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (d)(1) through (5) of this section.

(1) If a single continuous discharge meets any of the conditions specified in paragraphs (c)(1) through (3) of this section for 2 or more consecutive 24-hour periods, a single root cause analysis and corrective action analysis may be conducted.

(2) If a single discharge from a flare triggers a root cause analysis based on more than one of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section, a single root cause analysis and corrective action analysis may be conducted.

(3) If the discharge from a flare is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare and the procedures in paragraph (a)(5) of this section were followed, a root cause analysis and corrective action analysis is not required; however, the discharge must be recorded as described in §60.108a(c)(6) and reported as described in §60.108a(d)(5).

(4) If both the primary and secondary flare in a cascaded flare system meet any of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section in the same 24-hour period, a single root cause analysis and corrective action analysis may be conducted.

(5) Except as provided in paragraph (d)(4) of this section, if discharges occur that meet any of the conditions specified in paragraphs (c)(1) through (3) of this section for more than one affected facility in the same 24-hour period, initial root cause analyses shall be conducted for each affected facility. If the initial root cause analyses indicate that the discharges have the same root cause(s), the initial root cause analyses can be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

(e) Except as provided in paragraphs (f) and (g) of this section, each owner or operator of a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall implement the corrective action(s) identified in the corrective action analysis conducted pursuant to paragraph (d) of this section in accordance with the applicable requirements in paragraphs (e)(1) through (3) of this section.

(1) All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that corrective action should not be conducted, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the discharge as specified in §60.108a(c)(6)(ix).

(2) For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(3) No later than 45 days following the discharge for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates as specified in §60.108a(c)(6)(x).

(f) Modified flares shall comply with the requirements of paragraphs (c) through (e) of this section by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were not affected facilities subject to subpart J of this part prior to becoming affected facilities under §60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of §60.107a(a)(2) by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were affected facilities subject to subpart J of this part prior to becoming affected facilities under §60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of §60.107a(a)(2) by November 13, 2012 or at startup of the modified flare, whichever is later, except that modified flares that have accepted applicability of subpart J under a federal consent decree shall comply with the subpart J requirements as specified in the consent decree, but shall comply with the requirements of paragraph (h) of this section and the requirements of §60.107a(a)(2) by no later than November 11, 2015.

(g) An affected flare subject to this subpart located in the Bay Area Air Quality Management District (BAAQMD) may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. An affected flare subject to this subpart located in the South Coast Air Quality Management District (SCAQMD) may elect to comply with SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. The owner or operator of an affected flare must notify the Administrator that the flare is in compliance with BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 or SCAQMD Rule 1118. The owner or operator of an affected flare shall also submit the existing flare management plan to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refinerynsps@epa.gov.*

(h) Each owner or operator shall not burn in any affected flare any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis. 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 limit.

(i) Each owner or operator of a delayed coking unit shall depressure each coke drum to 5 lb per square inch gauge (psig) or less prior to discharging the coke drum steam exhaust to the atmosphere. Until the coke drum pressure reaches 5 psig, the coke drum steam exhaust must be managed in an enclosed blowdown system and the uncondensed vapor must either be recovered (e.g., sent to the delayed coking unit fractionators) or vented to the fuel gas system, a fuel gas combustion device or a flare.

(j) *Alternative means of emission limitation.* (1) Each owner or operator subject to the provisions of this section may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in emissions of a specified pollutant at least equivalent to the reduction in emissions of that pollutant achieved by the controls required in this section.

(2) Determination of equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(i) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate the equivalence of the alternative means of emission limitation.

(ii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.

(iii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(iv) Each owner or operator applying for a determination of equivalence to a work practice standard shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(v) The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in paragraph (j)(2)(iv) of this section.

(vi) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements.

(3) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(4) Approval of the application for equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(i) After a request for determination of equivalence is received, the Administrator will publish a notice in the FEDERAL REGISTER and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(ii) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER.

(iii) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design or operational standard within the meaning of section 111(h)(1) of the CAA.

(5) Manufacturers of equipment used to control emissions may apply to the Administrator for determination of equivalence for any alternative means of emission limitation that achieves a reduction in emissions achieved by the equipment, design and operational requirements of this section. The Administrator will make an equivalence determination according to the provisions of paragraphs (j)(2) through (4) of this section.

[77 FR 56467, Sep. 12, 2012]

§60.104a Performance tests.

(a) The owner or operator shall conduct a performance test for each FCCU, FCU, sulfur recovery plant and fuel gas combustion device to demonstrate initial compliance with each applicable emissions limit in §60.102a and conduct a performance test for each flare to demonstrate initial compliance with the H_2S concentration requirement in §60.103a(h) according to the requirements of §60.8. The notification requirements of §60.8(d) apply to the initial performance test and to subsequent performance tests required by paragraph (b) of this section (or as required by the Administrator), but does not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments.

(b) The owner or operator of a FCCU or FCU that elects to monitor control device operating parameters according to the requirements in §60.105a(b), to use bag leak detectors according to the requirements in §60.105a(c), or to use COMS according to the requirements in §60.105a(e) shall conduct a PM performance test at least annually (*i.e.*, once per calendar year, with an interval of at least 8 months but no more than 16 months between annual tests) and furnish the Administrator a written report of the results of each test.

(c) In conducting the performance tests required by this subpart (or as requested by the Administrator), the owner or operator shall use the test methods in 40 CFR part 60, Appendices A-1 through A-8 or other methods as specified in this section, except as provided in §60.8(b).

(d) The owner or operator shall determine compliance with the PM, NO_X, SO_2, and CO emissions limits in §60.102a(b) for FCCU and FCU using the following methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses.

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(4) Method 5, 5B, or 5F of appendix A-3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU without a wet scrubber subject to the emissions limit in §63.102a(b)(1). Use Method 5 or 5B of appendix A-3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU with a wet scrubber subject to the emissions limit in §63.102a(b)(1).

(i) The PM performance test consists of 3 valid test runs; the duration of each test run must be no less than 60 minutes.

(ii) The emissions rate of PM (E_{PM}) is computed for each run using Equation 5 of this section:

$$E = \frac{c_s Q_{sd}}{K R_c} \qquad \text{(Eq. 5)}$$

Where:

E = Emission rate of PM, g/kg (lb/1,000 lb) of coke burn-off;

c_s = Concentration of total PM, grams per dry standard cubic meter (g/dscm) (gr/dscf);

Q_{sd} = Volumetric flow rate of effluent gas, dry standard cubic meters per hour (dry standard cubic feet per hour);

R_c = Coke burn-off rate, kilograms per hour (kg/hr) [lb per hour (lb/hr)] coke; and

K = Conversion factor, 1.0 grams per gram (7,000 grains per lb).

(iii) The coke burn-off rate (R_c) is computed for each run using Equation 6 of this section:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \left(\%CO/2 + \%CO_2 + \%O_2 \right) + K_3 Q_{oxy} (\%O_{oxy})$$

(Eq. 6)

Where:

R_c = Coke burn-off rate, kg/hr (lb/hr);

Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emissions control or energy recovery system that burns auxiliary fuel, dry standard cubic meters per minute (dscm/min) [dry standard cubic feet per minute (dscf/min)];

Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Q_{oxy} = Volumetric flow rate of O_2 enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide (CO_2) concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%CO = CO concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

$\%O_2$ = O_2 concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis);

K_1 = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)];

K_2 = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) [0.1303 (lb-min)/(hr-dscf)]; and

K_3 = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.00624 (lb-min)/(hr-dscf-%)].

(iv) During the performance test, the volumetric flow rate of exhaust gas from catalyst regenerator (Q_r) before any emission control or energy recovery system that burns auxiliary fuel is measured using Method 2 of appendix A-1 to part 60.

(v) For subsequent calculations of coke burn-off rates or exhaust gas flow rates, the volumetric flow rate of Q_r is calculated using average exhaust gas concentrations as measured by the monitors required in §60.105a(b)(2), if applicable, using Equation 7 of this section:

$$Q_r = \frac{79 \times Q_a + (100 - \%Oxy) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. 7)}$$

Where:

Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emission control or energy recovery system that burns auxiliary fuel, dscm/min (dscf/min);

Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Q_{oxy} = Volumetric flow rate of O_2 enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%CO = CO concentration FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required in accordance with §60.105a(h)(3), assume %CO to be zero;

$\%O_2$ = O_2 concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis); and

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis).

(5) Method 6, 6A, or 6C of appendix A-4 to part 60 for moisture content and for the concentration of SO_2; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A-4 to part 60.

(6) Method 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 for moisture content and for the concentration of NO_X calculated as nitrogen dioxide (NO_2); the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A-4 to part 60.

(7) Method 10, 10A, or 10B of appendix A-4 to part 60 for moisture content and for the concentration of CO. The sampling time for each run must be 60 minutes.

(8) The owner or operator shall adjust PM, NO_X, SO_2 and CO pollutant concentrations to 0-percent excess air or 0-percent O_2 using Equation 8 of this section:

$$C_{adj} = C_{meas}\left[20.9_c \Big/ (20.9 - \%O_2)\right] \qquad \text{(Eq. 8)}$$

Where:

C_{adj} = pollutant concentration adjusted to 0-percent excess air or O_2, parts per million (ppm) or g/dscm;

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm;

20.9_c = 20.9 percent O_2−0.0 percent O_2 (defined O_2 correction basis), percent;

20.9 = O_2 concentration in air, percent; and

$\%O_2$ = O_2 concentration measured on a dry basis, percent.

(e) The owner or operator of a FCCU or FCU that is controlled by an electrostatic precipitator or wet scrubber and that is subject to control device operating parameter limits in §60.102a(c) shall establish the limits based on the performance test results according to the following procedures:

(1) Reduce the parameter monitoring data to hourly averages for each test run;

(2) Determine the hourly average operating limit for each required parameter as the average of the three test runs.

(f) The owner or operator of an FCCU or FCU that uses cyclones to comply with the PM per coke burn-off emissions limit in §60.102a(b)(1) shall establish a site-specific opacity operating limit according to the procedures in paragraphs (f)(1) through (3) of this section.

(1) Collect COMS data every 10 seconds during the entire period of the PM performance test and reduce the data to 6-minute averages.

(2) Determine and record the hourly average opacity from all the 6-minute averages.

(3) Compute the site-specific limit using Equation 9 of this section:

$$Opacity\ \ Limit = Opacity_{st}\ x\left(\frac{1\,\text{lb}/1{,}000\ \text{lb coke burn}}{PMEmR_{st}}\right) \qquad \text{(Eq. 9)}$$

Where:

Opacity limit = Maximum permissible 3-hour average opacity, percent, or 10 percent, whichever is greater;

$Opacity_{st}$ = Hourly average opacity measured during the source test, percent; and

$PMEmR_{st}$ = PM emission rate measured during the source test, lb/1,000 lb coke burn.

(g) The owner or operator of a FCCU or FCU that is exempt from the requirement to install and operate a CO CEMS pursuant to §60.105a(h)(3) and that is subject to control device operating parameter limits in §60.102a(c) shall establish the limits based on the performance test results using the procedures in paragraphs (g)(1) and (2) of this section.

(1) Reduce the temperature and O_2 concentrations from the parameter monitoring systems to hourly averages for each test run.

(2) Determine the operating limit for temperature and O_2 concentrations as the average of the average temperature and O_2 concentration for the three test runs.

(h) The owner or operator shall determine compliance with the SO_2 emissions limits for sulfur recovery plants in §60.102a(f)(1)(i) and (f)(2)(i) and the reduced sulfur compounds and H_2S emissions limits for sulfur recovery plants in §60.102a(f)(1)(ii), (f)(1)(iii), (f)(2)(ii), and (f)(2)(iii) using the following methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses.

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(4) Method 6, 6A, or 6C of appendix A-4 to part 60 to determine the SO_2 concentration. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A-4 to part 60.

(5) Method 15 or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to part 60 to determine the reduced sulfur compounds and H_2S concentrations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(i) Each run consists of 16 samples taken over a minimum of 3 hours.

(ii) The owner or operator shall calculate the average H_2S concentration after correcting for moisture and O_2 as the arithmetic average of the H_2S concentration for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iii) The owner or operator shall calculate the SO_2 equivalent for each run after correcting for moisture and O_2 as the arithmetic average of the SO_2 equivalent of reduced sulfur compounds for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iv) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O_2 or 0-percent excess air.

(6) If oxygen or oxygen-enriched air is used in the Claus burner and either Equation 1 or 2 of this subpart is used to determine the applicable emissions limit, determine the average O_2 concentration of the air/oxygen mixture supplied to the Claus burner, in percent by volume (dry basis), for the performance test using all hourly average O_2 concentrations determined during the test runs using the procedures in §60.106a(a)(5) or (6).

(i) The owner or operator shall determine compliance with the SO_2 and NO_X emissions limits in §60.102a(g) for a fuel gas combustion device according to the following test methods and procedures:

(1) Method 1 of appendix A-1 to part 60 for sample and velocity traverses;

(2) Method 2 of appendix A-1 to part 60 for velocity and volumetric flow rate;

(3) Method 3, 3A, or 3B of appendix A-2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60;

(4) Method 6, 6A, or 6C of appendix A-4 to part 60 to determine the SO_2 concentration. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A-4 to part 60.

(i) The performance test consists of 3 valid test runs; the duration of each test run must be no less than 1 hour.

(ii) If a single fuel gas combustion device having a common source of fuel gas is monitored as allowed under §60.107a(a)(1)(v), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance.

(5) Method 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 for moisture content and for the concentration of NO_X calculated as NO_2; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A-4 to part 60.

(6) For process heaters with a rated heat capacity between 40 and 100 MMBtu/hr that elect to demonstrate continuous compliance with a maximum excess oxygen limit as provided in §60.107a(c)(6) or (d)(8), the owner or operator shall establish the O_2 operating limit or O_2 operating curve based on the performance test results according to the requirements in paragraph (i)(6)(i) or (ii) of this section, respectively.

(i) If a single O_2 operating limit will be used:

(A) Conduct the performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section when the process heater is firing at no less than 70 percent of the rated heat capacity. For co-fired process heaters, conduct at least one of the test runs while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(B) Each test will consist of three test runs. Calculate the NO_X concentration for the performance test as the average of the NO_X concentrations from each of the three test runs. If the NO_X concentration for the performance test is less than or equal to the numerical value of the applicable NO_X emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) Determine the average O_2 concentration for each test run of a valid test.

(D) Calculate the O_2 operating limit as the average O_2 concentration of the three test runs from a valid test.

(ii) If an O_2 operating curve will be used:

(A) Conduct a performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section at a representative condition for each operating range for which different O_2 operating limits will be established. Different operating conditions may be defined as different firing rates (e.g., above 50 percent of rated heat capacity and at or below 50 percent of rated heat capacity) and/or, for co-fired process heaters, different fuel mixtures (e.g., primarily gas fired, primarily oil fired, and equally co-fired, *i.e.,* approximately 50 percent of the input heating value is from fuel gas and approximately 50 percent of the input heating value is from fuel oil). Performance tests for different operating ranges may be conducted at different times.

(B) Each test will consist of three test runs. Calculate the NO_X concentration for the performance test as the average of the NO_X concentrations from each of the three test runs. If the NO_X concentration for the performance test is less than or equal to the numerical value of the applicable NO_X emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) If an operating curve is developed for different firing rates, conduct at least one test when the process heater is firing at no less than 70 percent of the rated heat capacity and at least one test under turndown conditions (*i.e.,* when the process heater is firing at 50 percent or less of the rated heat capacity). If O_2 operating limits are developed for co-fired process heaters based only on overall firing rates (and not by fuel mixtures), conduct at least one of the test runs for each test while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(D) Determine the average O_2 concentration for each test run of a valid test.

(E) Calculate the O_2 operating limit for each operating range as the average O_2 concentration of the three test runs from a valid test conducted at the representative conditions for that given operating range.

(F) Identify the firing rates for which the different operating limits apply. If only two operating limits are established based on firing rates, the O_2 operating limits established when the process heater is firing at no less than 70 percent of the rated heat capacity must apply when the process heater is firing above 50 percent of the rated heat capacity and the O_2 operating limits established for turndown conditions must apply when the process heater is firing at 50 percent or less of the rated heat capacity.

(G) Operating limits associated with each interval will be valid for 2 years or until another operating limit is established for that interval based on a more recent performance test specific for that interval, whichever occurs first. Owners and operators must use the operating limits determined for a given interval based on the most recent performance test conducted for that interval.

(7) The owner or operator of a process heater complying with a NO_X limit in terms of lb/MMBtu as provided in §60.102a(g)(2)(i)(B), (g)(2)(ii)(B), (g)(2)(iii)(B) or (g)(2)(iv)(B) or a process heater with a rated heat capacity between 40 and 100 MMBtu/hr that elects to demonstrate continuous compliance with a maximum excess O_2 limit, as provided in §60.107a(c)(6) or (d)(8), shall determine heat input to the process heater in MMBtu/hr during each performance test run by measuring fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in §60.107a(d)(5), (d)(6), and (d)(4) or (d)(7), respectively.

(8) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O_2 or 0-percent excess air.

(j) The owner or operator shall determine compliance with the applicable H_2S emissions limit in §60.102a(g)(1) for a fuel gas combustion device or the concentration requirement in §60.103a(h) for a flare according to the following test methods and procedures:

(1)—(3) [Reserved]

(4) EPA Method 11, 15 or 15A of appendix A-5 to part 60 or EPA Method 16 of appendix A-6 to part 60 for determining the H_2S concentration for affected facilities using an H_2S monitor as specified in §60.107a(a)(2). The

method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60. The owner or operator may demonstrate compliance based on the mixture used in the fuel gas combustion device or flare or for each individual fuel gas stream used in the fuel gas combustion device or flare.

(i) For Method 11 of appendix A-5 to part 60, the sampling time and sample volume must be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times must be taken at about 1-hour intervals. The arithmetic average of these two samples constitutes 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 of appendix A-5 to part 60, at least three injects over a 1-hour period constitutes a run.

(iii) For Method 15A of appendix A-5 to part 60, a 1-hour sample constitutes a run. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(iv) If monitoring is conducted at a single point in a common source of fuel gas as allowed under §60.107a(a)(2)(iv), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device or flare is added to a common source of fuel gas that previously demonstrated compliance.

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§60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).

(a) *FCCU and FCU subject to PM emissions limit.* Each owner or operator subject to the provisions of this subpart shall monitor each FCCU and FCU subject to the PM emissions limit in §60.102a(b)(1) according to the requirements in paragraph (b), (c), (d), or (e) of this section.

(b) *Control device operating parameters.* Each owner or operator of a FCCU or FCU subject to the PM per coke burn-off emissions limit in §60.102a(b)(1) that uses a control device other than fabric filter or cyclone shall comply with the requirements in paragraphs (b)(1) and (2) of this section.

(1) The owner or operator shall install, operate and maintain continuous parameter monitor systems (CPMS) to measure and record operating parameters for each control device according to the applicable requirements in paragraphs (b)(1)(i) through (v) of this section.

(i) For units controlled using an electrostatic precipitator, the owner or operator shall use CPMS to measure and record the hourly average total power input and secondary current to the entire system.

(ii) For units controlled using a wet scrubber, the owner or operator shall use CPMS to measure and record the hourly average pressure drop, liquid feed rate, and exhaust gas flow rate. As an alternative to a CPMS, the owner or operator must comply with the requirements in either paragraph (b)(1)(ii)(A) or (B) of this section.

(A) As an alternative to pressure drop, the owner or operator of a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles must conduct a daily check of the air or water pressure to the spray nozzles and record the results of each check. Faulty (*e.g.*, leaking or plugged) air or water lines must be repaired within 12 hours of identification of an abnormal pressure reading.

(B) As an alternative to exhaust gas flow rate, the owner or operator shall comply with the approved alternative for monitoring exhaust gas flow rate in 40 CFR 63.1573(a) of the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

(iii) The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications and requirements.

(iv) The owner or operator shall determine and record the average coke burn-off rate and hours of operation for each FCCU or FCU using the procedures in §60.104a(d)(4)(iii).

(v) If you use a control device other than an electrostatic precipitator, wet scrubber, fabric filter, or cyclone, you may request approval to monitor parameters other than those required in paragraph (b)(1) of this section by submitting an alternative monitoring plan to the Administrator. The request must include the information in paragraphs (b)(1)(v)(A) through (E) of this section.

(A) A description of each affected facility and the parameter(s) to be monitored to determine whether the affected facility will continuously comply with the emission limitations and an explanation of the criteria used to select the parameter(s).

(B) A description of the methods and procedures that will be used to demonstrate that the parameter(s) can be used to determine whether the affected facility will continuously comply with the emission limitations and the schedule for this demonstration. The owner or operator must certify that an operating limit will be established for the monitored parameter(s) that represents the conditions in existence when the control device is being properly operated and maintained to meet the emission limitation.

(C) The frequency and content of the recordkeeping, recording, and reporting, if monitoring and recording are not continuous. The owner or operator also must include the rationale for the proposed monitoring, recording, and reporting requirements.

(D) Supporting calculations.

(E) Averaging time for the alternative operating parameter.

(2) For use in determining the coke burn-off rate for an FCCU or FCU, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring the concentrations of CO_2, O_2 (dry basis), and if needed, CO in the exhaust gases prior to any control or energy recovery system that burns auxiliary fuels. A CO monitor is not required for determining coke burn-off rate when no auxiliary fuel is burned and a continuous CO monitor is not required in accordance with paragraph (h)(3) of this section.

(i) The owner or operator shall install, operate, and maintain each CO_2 and O_2 monitor according to Performance Specification 3 of appendix B to this part.

(ii) The owner or operator shall conduct performance evaluations of each CO_2 and O_2 monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Method 3 of appendix A-3 to this part for conducting the relative accuracy evaluations.

(iii) If a CO monitor is required, the owner or operator shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of appendix B to this part. If this CO monitor also serves to demonstrate compliance with the CO emissions limit in §60.102a(b)(4), the span value for this instrument is 1,000 ppm; otherwise, the span value for this instrument should be set at approximately 2 times the typical CO concentration expected in the FCCU of FCU flue gas prior to any emission control or energy recovery system that burns auxiliary fuels.

(iv) If a CO monitor is required, the owner or operator shall conduct performance evaluations of each CO monitor according to the requirements in §60.13(c) and Performance Specification 4 of appendix B to this part. The owner or operator shall use Method 10, 10A, or 10B of appendix A-3 to this part for conducting the relative accuracy evaluations.

(v) The owner or operator shall comply with the quality assurance requirements of procedure 1 of appendix F to this part, including quarterly accuracy determinations for CO_2 and CO monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(c) *Bag leak detection systems.* Each owner or operator shall install, operate, and maintain a bag leak detection system for each baghouse or similar fabric filter control device that is used to comply with the PM per coke burn-off emissions limit in §60.102a(b)(1) for an FCCU or FCU according to paragraph (c)(1) of this section; prepare and operate by a site-specific monitoring plan according to paragraph (c)(2) of this section; take action according to paragraph (c)(3) of this section; and record information according to paragraph (c)(4) of this section.

(1) Each bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 0.00044 grains per actual cubic foot or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, the owner or operator shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(1)(vi) of this section.

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section.

(vii) The owner or operator shall install the bag leak detection sensor downstream of the baghouse and upstream of any wet scrubber.

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

(2) The owner or operator shall develop and submit to the Administrator for approval a site-specific monitoring plan for each baghouse and bag leak detection system. The owner or operator shall operate and maintain each baghouse and bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (c)(2)(i) through (vii) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored;

(vi) Procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable; and

(vii) How the baghouse system will be operated and maintained, including monitoring of pressure drop across baghouse cells and frequency of visual inspections of the baghouse interior and baghouse components such as fans and dust removal and bag cleaning mechanisms.

(3) For each bag leak detection system, the owner or operator shall initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator shall alleviate the cause of the alarm within 3 hours of the alarm by taking whatever action(s) are necessary. Actions may include, but are not limited to the following:

(i) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective baghouse compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the particulate emissions.

(4) The owner or operator shall maintain records of the information specified in paragraphs (c)(4)(i) through (iii) of this section for each bag leak detection system.

(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the alarm was alleviated within 3 hours of the alarm.

(d) *Continuous emissions monitoring systems (CEMS).* An owner or operator subject to the PM concentration emission limit (in gr/dscf) in §60.102a(b)(1) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (0 percent excess air) of PM in the exhaust gases prior to release to the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each PM monitor according to Performance Specification 11 of appendix B to part 60. The span value of this PM monitor is 0.08 gr/dscf PM.

(2) The owner or operator shall conduct performance evaluations of each PM monitor according to the requirements in §60.13(c) and Performance Specification 11 of appendix B to part 60. The owner or operator shall use EPA Methods 5 or 5I of appendix A-3 to part 60 or Method 17 of appendix A-6 to part 60 for conducting the relative accuracy evaluations.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60

shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 2 of appendix B to part 60 for each PM CEMS and Procedure 1 of appendix F to part 60 for each O_2 monitor, including quarterly accuracy determinations for each PM monitor, annual accuracy determinations for each O_2 monitor, and daily calibration drift tests.

(e) *Alternative monitoring option for FCCU and FCU—COMS.* Each owner or operator of an FCCU or FCU that uses cyclones to comply with the PM emission limit in §60.102a(b)(1) shall monitor the opacity of emissions according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The owner or operator shall install, operate, and maintain an instrument for continuously monitoring and recording the opacity of emissions from the FCCU or the FCU exhaust vent.

(2) The owner or operator shall install, operate, and maintain each COMS according to Performance Specification 1 of appendix B to part 60. The instrument shall be spanned at 20 to 60 percent opacity.

(3) The owner or operator shall conduct performance evaluations of each COMS according to §60.13(c) and Performance Specification 1 of appendix B to part 60.

(f) *FCCU and FCU subject to NO_X limit.* Each owner or operator subject to the NO_X emissions limit in §60.102a(b)(2) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, 0 percent excess air) of NO_X emissions into the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each NO_X monitor according to Performance Specification 2 of appendix B to part 60. The span value of this NO_X monitor is 200 ppmv NO_X.

(2) The owner or operator shall conduct performance evaluations of each NO_X monitor according to the requirements in §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A-4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 1 of appendix F to part 60 for each NO_X and O_2 monitor, including quarterly accuracy determinations for NO_X monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(g) *FCCU and FCU subject to SO_2 limit.* The owner or operator subject to the SO_2 emissions limit in §60.102a(b)(3) for an FCCU or an FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, corrected to 0 percent excess air) of SO_2 emissions into the atmosphere. The monitor shall include an O_2 monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each SO_2 monitor according to Performance Specification 2 of appendix B to part 60. The span value of this SO_2 monitor is 200 ppmv SO_2.

(2) The owner or operator shall conduct performance evaluations of each SO_2 monitor according to the requirements in §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 6, 6A, or 6C of appendix A-4 to part 60 for conducting the relative accuracy evaluations. The method ANSI / ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A-4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of appendix F to part 60 for each SO_2 and O_2 monitor, including quarterly accuracy determinations for SO_2 monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(h) *FCCU and fluid coking units subject to CO emissions limit.* Except as specified in paragraph (h)(3) of this section, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere from each FCCU and FCU subject to the CO emissions limit in §60.102a(b)(4).

(1) The owner or operator shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of appendix B to this part. The span value for this instrument is 1,000 ppmv CO.

(2) The owner or operator shall conduct performance evaluations of each CO monitor according to the requirements in §60.13(c) and Performance Specification 4 or 4A of appendix B to part 60. The owner or operator shall use Methods 10, 10A, or 10B of appendix A-4 to part 60 for conducting the relative accuracy evaluations.

(3) A CO CEMS need not be installed if the owner or operator demonstrates that all hourly average CO emissions are and will remain less than 50 ppmv (dry basis) corrected to 0 percent excess air. The Administrator may revoke this exemption from monitoring upon a determination that CO emissions on an hourly average basis have exceeded 50 ppmv (dry basis) corrected to 0 percent excess air, in which case a CO CEMS shall be installed within 180 days.

(i) The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that meets the requirements of Performance Specification 4 or 4A of appendix B to this part. The span value shall be 100 ppmv CO instead of 1,000 ppmv, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppmv CO, whichever is greater. For instruments that are identical to Method 10 of appendix A-4 to this part and employ the sample conditioning system of Method 10A of appendix A-4 to this part, the alternative relative accuracy test procedure in section 10.1 of Performance Specification 2 of appendix B to this part may be used in place of the relative accuracy test.

(ii) The owner or operator must submit the following information to the Administrator:

(A) The measurement data specified in paragraph (h)(3)(i) of this section along with all other operating data known to affect CO emissions; and

(B) Descriptions of the CPMS for exhaust gas temperature and O_2 monitor required in paragraph (h)(4) of this section and operating limits for those parameters to ensure combustion conditions remain similar to those that exist during the demonstration period.

(iii) The effective date of the exemption from installation and operation of a CO CEMS is the date of submission of the information and data required in paragraph (h)(3)(ii) of this section.

(4) The owner or operator of a FCCU or FCU that is exempted from the requirement to install and operate a CO CEMS in paragraph (h)(3) of this section shall install, operate, calibrate, and maintain CPMS to measure and record

the operating parameters in paragraph (h)(4)(i) or (ii) of this section. The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications.

(i) For a FCCU or FCU with no post-combustion control device, the temperature and O_2 concentration of the exhaust gas stream exiting the unit.

(ii) For a FCCU or FCU with a post-combustion control device, the temperature and O_2 concentration of the exhaust gas stream exiting the control device.

(i) *Excess emissions.* For the purpose of reports required by §60.7(c), periods of excess emissions for a FCCU or FCU subject to the emissions limitations in §60.102a(b) are defined as specified in paragraphs (i)(1) through (6) of this section. Note: Determine all averages, except for opacity, as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 3-hour average as the arithmetic average of three contiguous 1-hour averages.

(1) If a CPMS is used according to paragraph (b)(1) of this section, all 3-hour periods during which the average PM control device operating characteristics, as measured by the continuous monitoring systems under paragraph (b)(1), fall below the levels established during the performance test. If the alternative to pressure drop CPMS is used for the owner or operator of a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles, each day in which abnormal pressure readings are not corrected within 12 hours of identification.

(2) If a bag leak detection system is used according to paragraph (c) of this section, each day in which the cause of an alarm is not alleviated within the time period specified in paragraph (c)(3) of this section.

(3) If a PM CEMS is used according to §60.105a(d), all 7-day periods during which the average PM emission rate, as measured by the continuous PM monitoring system under §60.105a(d) exceeds 0.040 gr/dscf corrected to 0 percent excess air for a modified or reconstructed FCCU, 0.020 gr/dscf corrected to 0 percent excess air for a newly constructed FCCU, or 0.040 gr/dscf for an affected fluid coking unit.

(4) If a COMS is used according to §60.105a(e), all 3-hour periods during which the average opacity, as measured by the COMS under §60.105a(e), exceeds the site-specific limit established during the most recent performance test.

(5) All rolling 7-day periods during which the average concentration of NO_X as measured by the NO_X CEMS under §60.105a(f) exceeds 80 ppmv for an affected FCCU or FCU.

(6) All rolling 7-day periods during which the average concentration of SO_2 as measured by the SO_2 CEMS under §60.105a(g) exceeds 50 ppmv, and all rolling 365-day periods during which the average concentration of SO_2 as measured by the SO_2 CEMS exceeds 25 ppmv.

(7) All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under paragraph (h) of this section exceeds 500 ppmv or, if applicable, all 1-hour periods during which the average temperature and O_2 concentration as measured by the continuous monitoring systems under paragraph (h)(4) of this section fall below the operating limits established during the performance test.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56473, Sep. 12, 2012; 80 FR 75232, Dec. 1, 2015]

§60.106a Monitoring of emissions and operations for sulfur recovery plants.

(a) The owner or operator of a sulfur recovery plant that is subject to the emissions limits in §60.102a(f)(1) or §60.102a(f)(2) shall:

(1) For sulfur recovery plants subject to the SO_2 emission limit in §60.102a(f)(1)(i) or §60.102a(f)(2)(i), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of any SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span value for the SO_2 monitor is two times the applicable SO_2 emission limit at the highest O_2 concentration in the air/oxygen stream used in the Claus burner, if applicable.

(ii) The owner or operator shall install, operate, and maintain each SO_2 CEMS according to Performance Specification 2 of appendix B to part 60.

(iii) The owner or operator shall conduct performance evaluations of each SO_2 monitor according to the requirements in §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 6 or 6C of appendix A-4 to part 60 and Method 3 or 3A of appendix A-2 of part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6.

(iv) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to this part.

(v) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(vi) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to this part.

(vii) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to this part for each monitor, including annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(2) For sulfur recovery plants that are subject to the reduced sulfur compounds emission limit in §60.102a(f)(1)(ii) or (f)(2)(ii), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of reduced sulfur compounds and O_2 emissions into the atmosphere. The reduced sulfur compounds emissions shall be calculated as SO_2 (dry basis, zero percent excess air).

(i) The span value for the reduced sulfur compounds monitor is two times the applicable reduced sulfur compounds emission limit as SO_2 at the highest O_2 concentration in the air/oxygen stream used in the Claus burner, if applicable.

(ii) The owner or operator shall install, operate, and maintain each reduced sulfur compounds CEMS according to Performance Specification 5 of appendix B to this part.

(iii) The owner or operator shall conduct performance evaluations of each reduced sulfur compounds monitor according to the requirements in §60.13(c) and Performance Specification 5 of appendix B to this part. The owner or operator shall use Methods 15 or 15A of appendix A-5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(iv) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60.

(v) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(vi) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(vii) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to part 60 for each monitor, including annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(3) In place of the reduced sulfur compounds monitor required in paragraph (a)(2) of this section, the owner or operator may install, calibrate, operate, and maintain an instrument using an air or O_2 dilution and oxidation system to convert any reduced sulfur to SO_2 for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of the total resultant SO_2. The monitor must include an O_2 monitor for correcting the data for excess O_2.

(i) The span value for this monitor is two times the applicable reduced sulfur compounds emission limit as SO_2 at the highest O_2 concentration in the air/oxygen stream used in the Claus burner, if applicable.

(ii) The owner or operator shall conduct performance evaluations of each SO_2 monitor according to the requirements in §60.13(c) and Performance Specification 5 of appendix B to part 60. The owner or operator shall use Methods 15 or 15A of appendix A-5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(iii) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60.

(iv) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(v) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(vi) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to part 60 for each monitor, including quarterly accuracy determinations for each SO_2 monitor, annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(4) For sulfur recovery plants that are subject to the H_2S emission limit in §60.102a(f)(1)(iii) or (f)(2)(iii), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of H_2S, and O_2 emissions into the atmosphere. The H_2S emissions shall be calculated as SO_2 (dry basis, zero percent excess air).

(i) The span value for this monitor is two times the applicable H_2S emission limit.

(ii) The owner or operator shall install, operate, and maintain each H_2S CEMS according to Performance Specification 7 of appendix B to this part.

(iii) The owner or operator shall conduct performance evaluations for each H_2S monitor according to the requirements of §60.13(c) and Performance Specification 7 of appendix B to this part. The owner or operator shall use Methods 11 or 15 of appendix A-5 to this part or Method 16 of appendix A-6 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to this part.

(iv) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to this part.

(v) The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(vi) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to this part.

(vii) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to this part for each monitor, including annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(5) For sulfur recovery plants that use oxygen or oxygen enriched air in the Claus burner and that elects to monitor O_2 concentration of the air/oxygen mixture supplied to the Claus burner, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the O_2 concentration of the air/oxygen mixture supplied to the Claus burner in order to determine the allowable emissions limit.

(i) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to this part.

(ii) The span value for the O_2 monitor shall be 100 percent.

(iii) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to this part. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to this part.

(iv) The owner or operator shall comply with the applicable quality assurance procedures of appendix F to this part for each monitor, including annual accuracy determinations for each O_2 monitor, and daily calibration drift determinations.

(v) The owner or operator shall use the hourly average O_2 concentration from this monitor for use in Equation 1 or 2 of §60.102a(f), as applicable, for each hour and determine the allowable emission limit as the arithmetic average of 12 contiguous 1-hour averages (*i.e.*, the rolling 12-hour average).

(6) As an alternative to the O_2 monitor required in paragraph (a)(5) of this section, the owner or operator may install, calibrate, operate, and maintain a CPMS to measure and record the volumetric gas flow rate of ambient air and oxygen-enriched gas supplied to the Claus burner and calculate the hourly average O_2 concentration of the air/oxygen mixture used in the Claus burner as specified in paragraphs (a)(6)(i) through (iv) of this section in order to determine the allowable emissions limit as specified in paragraphs (a)(6)(v) of this section.

(i) The owner or operator shall install, calibrate, operate and maintain each flow monitor according to the manufacturer's procedures and specifications and the following requirements.

(A) Locate the monitor in a position that provides a representative measurement of the total gas flow rate.

(B) Use a flow sensor meeting an accuracy requirement of ±5 percent over the normal range of flow measured or 10 cubic feet per minute, whichever is greater.

(C) Use a flow monitor that is maintainable online, is able to continuously correct for temperature, pressure and, for ambient air flow monitor, moisture content, and is able to record dry flow in standard conditions (as defined in §60.2) over one-minute averages.

(D) At least quarterly, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if the flow monitor is not equipped with a redundant flow sensor.

(E) Recalibrate the flow monitor in accordance with the manufacturer's procedures and specifications biennially (every two years) or at the frequency specified by the manufacturer.

(ii) The owner or operator shall use 20.9 percent as the oxygen content of the ambient air.

(iii) The owner or operator shall use product specifications (*e.g.,* as reported in material safety data sheets) for percent oxygen for purchased oxygen. For oxygen produced onsite, the percent oxygen shall be determined by periodic measurements or process knowledge.

(iv) The owner or operator shall calculate the hourly average O_2 concentration of the air/oxygen mixture used in the Claus burner using Equation 10 of this section:

$$\%O_2 = \left(\frac{20.9 \times Q_{air} + \%O_{2,oxy} \times Q_{oxy}}{Q_{air} + Q_{oxy}} \right) \qquad \text{(Eq. 10)}$$

Where:

$\%O_2$ = O_2 concentration of the air/oxygen mixture used in the Claus burner, percent by volume (dry basis);

20.9 = O_2 concentration in air, percent dry basis;

Q_{air} = Volumetric flow rate of ambient air used in the Claus burner, dscfm;

$\%O_{2,oxy}$ = O_2 concentration in the enriched oxygen stream, percent dry basis; and

Q_{oxy} = Volumetric flow rate of enriched oxygen stream used in the Claus burner, dscfm.

(v) The owner or operator shall use the hourly average O_2 concentration determined using Equation 8 of §60.104a(d)(8) for use in Equation 1 or 2 of §60.102a(f), as applicable, for each hour and determine the allowable emission limit as the arithmetic average of 12 contiguous 1-hour averages (*i.e.,* the rolling 12-hour average).

(7) Owners or operators of a sulfur recovery plant that elects to comply with the SO_2 emission limit in §60.102a(f)(1)(i) or (f)(2)(i) or the reduced sulfur compounds emission limit in §60.102a(f)(1)(ii) or (f)(2)(ii) as a flow rate weighted average for a group of release points from the sulfur recovery plant rather than for each process train or release point individually shall install, calibrate, operate, and maintain a CPMS to measure and record the volumetric gas flow rate of each release point within the group of release points from the sulfur recovery plant as specified in paragraphs (a)(7)(i) through (iv) of this section.

(i) The owner or operator shall install, calibrate, operate and maintain each flow monitor according to the manufacturer's procedures and specifications and the following requirements.

(A) Locate the monitor in a position that provides a representative measurement of the total gas flow rate.

(B) Use a flow sensor meeting an accuracy requirement of ±5 percent over the normal range of flow measured or 10 cubic feet per minute, whichever is greater.

(C) Use a flow monitor that is maintainable online, is able to continuously correct for temperature, pressure, and moisture content, and is able to record dry flow in standard conditions (as defined in §60.2) over one-minute averages.

(D) At least quarterly, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if the flow monitor is not equipped with a redundant flow sensor.

(E) Recalibrate the flow monitor in accordance with the manufacturer's procedures and specifications biennially (every two years) or at the frequency specified by the manufacturer.

(ii) The owner or operator shall correct the flow to 0 percent excess air using Equation 11 of this section:

$$Q_{adj} = Q_{meas}\left[\left(20.9 - \%O_2\right) \Big/ 20.9_c\right] \qquad \text{(Eq. 11)}$$

Where:

Q_{adj} = Volumetric flow rate adjusted to 0 percent excess air, dry standard cubic feet per minute (dscfm);

C_{meas} = Volumetric flow rate measured by the flow meter corrected to dry standard conditions, dscfm;

20.9_c = 20.9 percent O_2−0.0 percent O_2 (defined O_2 correction basis), percent;

20.9 = O_2 concentration in air, percent; and

$\%O_2$ = O_2 concentration measured on a dry basis, percent.

(iii) The owner or operator shall calculate the flow weighted average SO_2 or reduced sulfur compounds concentration for each hour using Equation 12 of this section:

$$C_{ave} = \frac{\sum_{n=1}^{N}\left(C_n \times Q_{adj,n}\right)}{\sum_{n=1}^{N} Q_{adj,n}} \qquad \text{(Eq. 12)}$$

Where:

C_{ave} = Flow weighted average concentration of the pollutant, ppmv (dry basis, zero percent excess air). The pollutant is either SO_2 (if complying with the SO_2 emission limit in §60.102a(f)(1)(i) or (f)(2)(i)) or reduced sulfur compounds (if complying with the reduced sulfur compounds emission limit in §60.102a(f)(1)(ii) or (f)(2)(ii));

N = Number of release points within the group of release points from the sulfur recovery plant for which emissions averaging is elected;

C_n = Pollutant concentration in the nth release point within the group of release points from the sulfur recovery plant for which emissions averaging is elected, ppmv (dry basis, zero percent excess air);

$Q_{adj,n}$ = Volumetric flow rate of the nth release point within the group of release points from the sulfur recovery plant for which emissions averaging is elected, dry standard cubic feet per minute (dscfm, adjusted to 0 percent excess air).

(iv) For sulfur recovery plants that use oxygen or oxygen enriched air in the Claus burner, the owner or operator shall use Equation 10 of this section and the hourly emission limits determined in paragraph (a)(5)(v) or (a)(6)(v) of this section in-place of the pollutant concentration to determine the flow weighted average hourly emission limit for each hour. The allowable emission limit shall be calculated as the arithmetic average of 12 contiguous 1-hour averages (*i.e.,* the rolling 12-hour average).

(b) *Excess emissions.* For the purpose of reports required by §60.7(c), periods of excess emissions for sulfur recovery plants subject to the emissions limitations in §60.102a(f) are defined as specified in paragraphs (b)(1) through (3) of this section.

NOTE: Determine all averages as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 12-hour average as the arithmetic average of 12 contiguous 1-hour averages.

(1) All 12-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system required under paragraph (a)(1) of this section exceeds the applicable emission limit (dry basis, zero percent excess air); or

(2) All 12-hour periods during which the average concentration of reduced sulfur compounds (as SO_2) as measured by the reduced sulfur compounds continuous monitoring system required under paragraph (a)(2) or (3) of this section exceeds the applicable emission limit; or

(3) All 12-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under paragraph (a)(4) of this section exceeds the applicable emission limit (dry basis, 0 percent excess air).

[73 FR 35867, June 24, 2008, as amended at 80 FR 75232, Dec. 1, 2015]

§60.107a Monitoring of emissions and operations for fuel gas combustion devices and flares.

(a) *Fuel gas combustion devices subject to* SO_2 or H_2S *limit and flares subject to* H_2S *concentration requirements.* The owner or operator of a fuel gas combustion device that is subject to §60.102a(g)(1) and elects to comply with the SO_2 emission limits in §60.102a(g)(1)(i) shall comply with the requirements in paragraph (a)(1) of this section. The owner or operator of a fuel gas combustion device that is subject to §60.102a(g)(1) and elects to comply with the H_2S concentration limits in §60.102a(g)(1)(ii) or a flare that is subject to the H_2S concentration requirement in §60.103a(h) shall comply with paragraph (a)(2) of this section.

(1) The owner or operator of a fuel gas combustion device that elects to comply with the SO_2 emissions limits in §60.102a(g)(1)(i) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of SO_2 emissions into the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air.

(i) The owner or operator shall install, operate, and maintain each SO_2 monitor according to Performance Specification 2 of appendix B to this part. The span value for the SO_2 monitor is 50 ppmv SO_2.

(ii) The owner or operator shall conduct performance evaluations for the SO_2 monitor according to the requirements of §60.13(c) and Performance Specification 2 of appendix B to this part. The owner or operator shall use Methods 6, 6A, or 6C of appendix A-4 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 6 or 6A of appendix A-4 to this part. Samples taken by Method 6 of appendix A-4 to this part 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 ppmv, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iii) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value for the O_2 monitor must be selected between 10 and 25 percent, inclusive.

(iv) The owner or operator shall conduct performance evaluations for the O_2 monitor according to the requirements of §60.13(c) and Performance Specification 3 of appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of appendix A-2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(v) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60, including quarterly accuracy determinations for SO_2 monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

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

(2) The owner or operator of a fuel gas combustion device that elects to comply with the H_2S concentration limits in §60.102a(g)(1)(ii) or a flare that is subject to the H_2S concentration requirement in §60.103a(h) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases before being burned in any fuel gas combustion device or flare.

(i) The owner or operator shall install, operate and maintain each H_2S monitor according to Performance Specification 7 of appendix B to part 60. The span value for this instrument is 300 ppmv H_2S.

(ii) The owner or operator shall conduct performance evaluations for each H_2S monitor according to the requirements of §60.13(c) and Performance Specification 7 of appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of appendix A-5 to part 60 or Method 16 of appendix A-6 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to part 60.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60 for each H_2S monitor.

(iv) Fuel gas combustion devices or flares 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 in the respective fuel gas combustion devices or flares.

(v) The owner or operator of a flare subject to §60.103a(c) through (e) may use the instrument required in paragraph (e)(1) of this section to demonstrate compliance with the H_2S concentration requirement in §60.103a(h) if the owner or operator complies with the requirements of paragraph (e)(1)(i) through (iv) and if the instrument has a span (or dual span, if necessary) capable of accurately measuring concentrations between 20 and 300 ppmv. If the instrument required in paragraph (e)(1) of this section is used to demonstrate compliance with the H_2S concentration requirement, the concentration directly measured by the instrument must meet the numeric concentration in §60.103a(h).

(vi) The owner or operator of modified flare that meets all three criteria in paragraphs (a)(2)(vi)(A) through (C) of this section shall comply with the requirements of paragraphs (a)(2)(i) through (v) of this section no later than November 11, 2015. The owner or operator shall comply with the approved alternative monitoring plan or plans pursuant to §60.13(i) until the flare is in compliance with requirements of paragraphs (a)(2)(i) through (v) of this section.

(A) The flare was an affected facility subject to subpart J of this part prior to becoming an affected facility under §60.100a.

(B) The owner or operator had an approved alternative monitoring plan or plans pursuant to §60.13(i) for all fuel gases combusted in the flare.

(C) The flare did not have in place on or before September 12, 2012 an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases that is capable of complying with the requirements of paragraphs (a)(2)(i) through (v) of this section.

(3) The owner or operator of a fuel gas combustion device or flare is not required to comply with paragraph (a)(1) or (2) of this section for fuel gas streams that are exempt under §§60.102a(g)(1)(iii) or 60.103a(h) or, for fuel gas streams combusted in a process heater, other fuel gas combustion device or flare that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(3)(i) through (iv) of this section will be considered inherently low in sulfur content.

(i) Pilot gas for heaters and flares.

(ii) Fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less. In the case of a liquefied petroleum gas (LPG) product specification in the pressurized liquid state, the gas phase sulfur content should be evaluated assuming complete vaporization of the LPG and sulfur containing-compounds at the product specification concentration.

(iii) Fuel gas streams produced in process units that are intolerant to sulfur contamination, such as fuel gas streams produced in the hydrogen plant, catalytic reforming unit, isomerization unit, and HF alkylation process units.

(iv) Other fuel gas streams that an owner or operator demonstrates are low-sulfur according to the procedures in paragraph (b) of this section.

(4) If the composition of an exempt fuel gas stream changes, the owner or operator must follow the procedures in paragraph (b)(3) of this section.

(b) *Exemption from H_2S monitoring requirements for low-sulfur fuel gas streams.* The owner or operator of a fuel gas combustion device or flare may apply for an exemption from the H_2S monitoring requirements in paragraph (a)(2) of this section for a fuel gas stream that is inherently low in sulfur content. A fuel gas stream that is demonstrated to be low-sulfur is exempt from the monitoring requirements of paragraphs (a)(1) and (2) of this section until there are changes in operating conditions or stream composition.

(1) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(i) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system and the affected fuel gas combustion device(s) or flare(s) to be considered;

(ii) A statement that there are no crossover or entry points for sour gas (high H_2S content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);

(iii) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppmv H_2S. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes (“length-of-stain tube” type measurement) following the “Gas Processors Association Standard 2377-86 (incorporated by reference—see §60.17), using tubes with a maximum span between 10 and 40 ppmv inclusive when $1 \le N \le 10$, where N = number of pump strokes, to test the applicant fuel gas stream for H_2S; and

(v) A description of how the 2 weeks (or seven samples for infrequently operated fuel gas streams/systems) of monitoring results compares to the typical range of H_2S concentration (fuel quality) expected for the fuel gas stream/system going to the affected fuel gas combustion device or flare (e.g., the 2 weeks of daily detector tube results for a frequently operated loading rack included the entire range of products loaded out and, therefore, should be representative of typical operating conditions affecting H_2S content in the fuel gas stream going to the loading rack flare).

(2) The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section.

(3) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator shall follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section.

(i) If the operation change results in a sulfur content that is still within the range of concentrations included in the original application, the owner or operator shall conduct an H_2S test on a grab sample and record the results as proof that the concentration is still within the range.

(ii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, the owner or operator may submit new information following the procedures of paragraph (b)(1) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(iii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application and the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin H_2S monitoring using daily stain sampling to demonstrate compliance using length-of-stain tubes with a maximum span between 200 and 400 ppmv inclusive when $1 \le N \le 5$, where N = number of pump strokes. The owner or operator must begin monitoring according to the requirements in paragraphs (a)(1) or (a)(2) of this section as soon as practicable, but in no case later than 180 days after the operation change. During daily stain tube sampling, a daily sample exceeding 162 ppmv is an exceedance of the 3-hour H_2S concentration limit. The owner or operator of a fuel gas combustion device must also determine a rolling 365-day average using the stain sampling results; an average H_2S concentration of 5 ppmv must be used for days within the rolling 365-day period prior to the operation change.

(c) *Process heaters complying with the NO_X concentration-based limit.* The owner or operator of a process heater subject to the NO_X emissions limit in §60.102a(g)(2) and electing to comply with the applicable emissions limit in §60.102a(g)(2)(i)(A), (g)(2)(ii)(A), (g)(2)(iii)(A) or (g)(2)(iv)(A) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_X emissions into the atmosphere according to the requirements in paragraphs (c)(1) through (5) of this section, except as provided in paragraph (c)(6) of this section. The monitor must include an O_2 monitor for correcting the data for excess air.

(1) Except as provided in paragraph (c)(6) of this section, the owner or operator shall install, operate and maintain each NO_X monitor according to Performance Specification 2 of appendix B to part 60. The span value of this NO_X monitor must be between 2 and 3 times the applicable emissions limit, inclusive.

(2) The owner or operator shall conduct performance evaluations of each NO_X monitor according to the requirements in §60.13(c) and Performance Specification 2 of appendix B to part 60. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E of appendix A-4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 7 or 7C of appendix A-4 to part 60.

(3) The owner or operator shall install, operate, and maintain each O_2 monitor according to Performance Specification 3 of appendix B to part 60. The span value of this O_2 monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each O_2 monitor according to the requirements in §60.13(c) and Performance Specification 3 of appendix B to part 60. Method 3, 3A, or 3B of appendix A-2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 3B of appendix A-2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of appendix F to part 60 for each NO_X and O_2 monitor, including quarterly accuracy determinations for NO_X monitors, annual accuracy determinations for O_2 monitors, and daily calibration drift tests.

(6) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with combustion modification-based technology to reduce NO_X emissions (*i.e.,* low-NO_X burners, ultra-low-NO_X burners) may elect to comply with the monitoring requirements in paragraphs (c)(1) through (5) of this section or, alternatively, the owner or operator of such a process heater shall conduct biennial performance tests according to the requirements in §60.104a(i), establish a maximum excess O_2 operating limit or operating curve according to the requirements in §60.104a(i)(6) and comply with the O_2 monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance. If an O_2 operating curve is used (*i.e.,* if different O_2 operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of this section, respectively.

(d) *Process heaters complying with the NO_X heating value-based or mass-based limit.* The owner or operator of a process heater subject to the NO_X emissions limit in §60.102a(g)(2) and electing to comply with the applicable emissions limit in §60.102a(g)(2)(i)(B) or (g)(2)(ii)(B) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_X emissions into the atmosphere and shall determine the F factor of the fuel gas stream no less frequently than once per day according to the monitoring requirements in paragraphs (d)(1) through (4) of this section. The owner or operator of a co-fired process heater subject to the NO_X emissions limit in §60.102a(g)(2) and electing to comply with the heating value-based limit in §60.102a(g)(2)(iii)(B) or (g)(2)(iv)(B) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_X emissions into the atmosphere according to the monitoring requirements in paragraph (d)(1) of this section; install, operate, calibrate and maintain an instrument for continuously monitoring and recording the flow rate of the fuel gas and fuel oil fed to the process heater according to the monitoring requirements in paragraph (d)(5) and (6) of this section; for fuel gas streams, determine gas composition according to the requirements in paragraph (d)(4) of this section or the higher heating value according to the requirements in paragraph (d)(7) of this section; and for fuel oil streams, determine the heating value according to the monitoring requirements in paragraph (d)(7) of this section.

(1) Except as provided in paragraph (d)(8) of this section, the owner or operator shall install, operate and maintain each NO_X monitor according to the requirements in paragraphs (c)(1) through (5) of this section. The monitor must include an O_2 monitor for correcting the data for excess air.

(2) Except as provided in paragraph (d)(3) of this section, the owner or operator shall sample and analyze each fuel stream fed to the process heater using the methods and equations in section 12.3.2 of EPA Method 19 of appendix A-7 to part 60 to determine the F factor on a dry basis. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).

(3) As an alternative to the requirements in paragraph (d)(2) of this section, the owner or operator of a gas-fired process heater shall install, operate and maintain a gas composition analyzer and determine the average F factor of the fuel gas using the factors in Table 1 of this subpart and Equation 13 of this section. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).

$$F_d = \frac{1{,}000{,}000 \times \sum (X_i \times MEV_i)}{\sum (X_i \times MHC_i)} \qquad \text{(Eq. 13)}$$

Where:

F_d = F factor on dry basis at 0% excess air, dscf/MMBtu.

X_i = mole or volume fraction of each component in the fuel gas.

MEV_i = molar exhaust volume, dry standard cubic feet per mole (dscf/mol).

MHC_i = molar heat content, Btu per mole (Btu/mol).

1,000,000 = unit conversion, Btu per MMBtu.

(4) The owner or operator shall conduct performance evaluations of each compositional monitor according to the requirements in Performance Specification 9 of appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) EPA Method 18 of appendix A-6 to part 60;

(ii) ASTM D1945-03 (Reapproved 2010)(incorporated by reference-see §60.17);

(iii) ASTM D1946-90 (Reapproved 2006)(incorporated by reference-see §60.17);

(iv) ASTM D6420-99 (Reapproved 2004)(incorporated by reference-see §60.17);

(v) GPA 2261-00 (incorporated by reference-see §60.17); or

(vi) ASTM UOP539-97 (incorporated by reference-see §60.17).

(5) The owner or operator shall install, operate and maintain fuel gas flow monitors according to the manufacturer's recommendations. For volumetric flow meters, temperature and pressure monitors must be installed in conjunction

with the flow meter or in a representative location to correct the measured flow to standard conditions (*i.e.,* 68 °F and 1 atmosphere). For mass flow meters, use gas compositions determined according to paragraph (d)(4) of this section to determine the average molecular weight of the fuel gas and convert the mass flow to a volumetric flow at standard conditions (*i.e.,* 68 °F and 1 atmosphere). The owner or operator shall conduct performance evaluations of each fuel gas flow monitor according to the requirements in §60.13 and Performance Specification 6 of appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) EPA Method 2, 2A, 2B, 2C or 2D of appendix A-2 to part 60;

(ii) ASME MFC-3M-2004 (incorporated by reference-see §60.17);

(iii) ANSI/ASME MFC-4M-1986 (Reaffirmed 2008) (incorporated by reference-see §60.17);

(iv) ASME MFC-6M-1998 (Reaffirmed 2005) (incorporated by reference-see §60.17);

(v) ASME/ANSI MFC-7M-1987 (Reaffirmed 2006) (incorporated by reference-see §60.17);

(vi) ASME MFC-11M-2006 (incorporated by reference-see §60.17);

(vii) ASME MFC-14M-2003 (incorporated by reference-see §60.17);

(viii) ASME MFC-18M-2001 (incorporated by reference-see §60.17);

(ix) AGA Report No. 3, Part 1 (incorporated by reference-see §60.17);

(x) AGA Report No. 3, Part 2 (incorporated by reference-see §60.17);

(xi) AGA Report No. 11 (incorporated by reference-see §60.17);

(xii) AGA Report No. 7 (incorporated by reference-see §60.17); and

(xiii) API Manual of Petroleum Measurement Standards, Chapter 22, Section 2 (incorporated by reference-see §60.17).

(6) The owner or operator shall install, operate and maintain each fuel oil flow monitor according to the manufacturer's recommendations. The owner or operator shall conduct performance evaluations of each fuel oil flow monitor according to the requirements in §60.13 and Performance Specification 6 of appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) Any one of the methods listed in paragraph (d)(5) of this section that are applicable to fuel oil (*i.e.,* “fluids”);

(ii) ANSI/ASME-MFC-5M-1985 (Reaffirmed 2006) (incorporated by reference-see §60.17);

(iii) ASME/ANSI MFC-9M-1988 (Reaffirmed 2006) (incorporated by reference-see §60.17);

(iv) ASME MFC-16-2007 (incorporated by reference-see §60.17);

(v) ASME MFC-22-2007 (incorporated by reference-see §60.17); or

(vi) ISO 8316 (incorporated by reference-see §60.17).

(7) The owner or operator shall determine the higher heating value of each fuel fed to the process heater using any of the applicable methods included in paragraphs (d)(7)(i) through (ix) of this section. If a common fuel supply system provides fuel gas or fuel oil to several process heaters, the higher heating value of the fuel in each fuel supply system may be determined at a single location in the fuel supply system provided it is representative of the fuel fed to the

affected process heater(s). The higher heating value of each fuel fed to the process heater must be determined no less frequently than once per day except as provided in paragraph (d)(7)(x) of this section.

(i) ASTM D240-02 (Reapproved 2007) (incorporated by reference-see §60.17).

(ii) ASTM D1826-94 (Reapproved 2003) (incorporated by reference-see §60.17).

(iii) ASTM D1945-03 (Reapproved 2010) (incorporated by reference-see §60.17).

(iv) ASTM D1946-90 (Reapproved 2006) (incorporated by reference-see §60.17).

(v) ASTM D3588-98 (Reapproved 2003) (incorporated by reference-see §60.17).

(vi) ASTM D4809-06 (incorporated by reference-see §60.17).

(vii) ASTM D4891-89 (Reapproved 2006) (incorporated by reference-see §60.17).

(viii) GPA 2172-09 (incorporated by reference-see §60.17).

(ix) Any of the methods specified in section 2.2.7 of appendix D to part 75.

(x) If the fuel oil supplied to the affected co-fired process heater originates from a single storage tank, the owner or operator may elect to use the storage tank sampling method in section 2.2.4.2 of appendix D to part 75 instead of daily sampling, except that the most recent value for heating content must be used.

(8) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with combustion modification based technology to reduce NO_X emissions (*i.e.,* low-NO_X burners or ultra-low NO_X burners) may elect to comply with the monitoring requirements in paragraphs (d)(1) through (7) of this section or, alternatively, the owner or operator of such a process heater shall conduct biennial performance tests according to the requirements in §60.104a(i), establish a maximum excess O_2 operating limit or operating curve according to the requirements in §60.104a(i)(6) and comply with the O_2 monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance. If an O_2 operating curve is used (*i.e.,* if different O_2 operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of this section, respectively.

(e) *Sulfur monitoring for assessing root cause analysis threshold for affected flares.* Except as described in paragraphs (e)(4) and (h) of this section, the owner or operator of an affected flare subject to §60.103a(c) through (e) shall determine the total reduced sulfur concentration for each gas line directed to the affected flare in accordance with either paragraph (e)(1), (e)(2) or (e)(3) of this section. Different options may be elected for different gas lines. If a monitoring system is in place that is capable of complying with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section, the owner or operator of a modified flare must comply with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section upon startup of the modified flare. If a monitoring system is not in place that is capable of complying with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section, the owner or operator of a modified flare must comply with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) *Total reduced sulfur monitoring requirements.* The owner or operator shall install, operate, calibrate and maintain an instrument or instruments for continuously monitoring and recording the concentration of total reduced sulfur in gas discharged to the flare.

(i) The owner or operator shall install, operate and maintain each total reduced sulfur monitor according to Performance Specification 5 of appendix B to part 60. The span value should be determined based on the maximum sulfur content of gas that can be discharged to the flare (e.g., roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but may be no less than 5,000 ppmv. A single dual range monitor may be used to comply with the requirements of this paragraph and paragraph (a)(2) of this section provided the applicable span specifications are met.

(ii) The owner or operator shall conduct performance evaluations of each total reduced sulfur monitor according to the requirements in §60.13(c) and Performance Specification 5 of appendix B to this part. The owner or operator of each total reduced sulfur monitor shall use EPA Method 15A of appendix A-5 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference-see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to this part. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of appendix B to this part (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60 for each total reduced sulfur monitor.

(2) *H_2S monitoring requirements.* The owner or operator shall install, operate, calibrate, and maintain an instrument or instruments for continuously monitoring and recording the concentration of H_2S in gas discharged to the flare according to the requirements in paragraphs (e)(2)(i) through (iii) of this section and shall collect and analyze samples of the gas and calculate total sulfur concentrations as specified in paragraphs (e)(2)(iv) through (ix) of this section.

(i) The owner or operator shall install, operate and maintain each H_2S monitor according to Performance Specification 7 of appendix B to part 60. The span value should be determined based on the maximum sulfur content of gas that can be discharged to the flare (e.g., roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but may be no less than 5,000 ppmv. A single dual range H_2S monitor may be used to comply with the requirements of this paragraph and paragraph (a)(2) of this section provided the applicable span specifications are met.

(ii) The owner or operator shall conduct performance evaluations of each H_2S monitor according to the requirements in §60.13(c) and Performance Specification 7 of appendix B to this part. The owner or operator shall use EPA Method 11, 15 or 15A of appendix A-5 to this part for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981 (incorporated by reference—see §60.17) is an acceptable alternative to EPA Method 15A of appendix A-5 to this part. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of appendix B to this part (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in appendix F to part 60 for each H_2S monitor.

(iv) In the first 10 operating days after the date the flare must begin to comply with §60.103a(c)(1), the owner or operator shall collect representative daily samples of the gas discharged to the flare. The samples may be grab samples or integrated samples. The owner or operator shall take subsequent representative daily samples at least once per week or as required in paragraph (e)(2)(ix) of this section.

(v) The owner or operator shall analyze each daily sample for total sulfur using either EPA Method 15A of appendix A-5 to part 60, EPA Method 16A of appendix A-6 to part 60, ASTM Method D4468-85 (Reapproved 2006) (incorporated by reference—see §60.17) or ASTM Method D5504-08 (incorporated by reference—see §60.17).

(vi) The owner or operator shall develop a 10-day average total sulfur-to-H_2S ratio and 95-percent confidence interval as follows:

(A) Calculate the ratio of the total sulfur concentration to the H_2S concentration for each day during which samples are collected.

(B) Determine the 10-day average total sulfur-to-H_2S ratio as the arithmetic average of the daily ratios calculated in paragraph (e)(2)(vi)(A) of this section.

(C) Determine the acceptable range for subsequent weekly samples based on the 95-percent confidence interval for the distribution of daily ratios based on the 10 individual daily ratios using Equation 14 of this section.

$$AR = Ratio_{Avg} \pm 2.262 \times SDev \qquad \text{(Eq. 14)}$$

Where:

AR = Acceptable range of subsequent ratio determinations, unitless.

$Ratio_{Avg}$ = 10-day average total sulfur-to-H_2S concentration ratio, unitless.

2.262 = t-distribution statistic for 95-percent 2-sided confidence interval for 10 samples (9 degrees of freedom).

SDev = Standard deviation of the 10 daily average total sulfur-to-H_2S concentration ratios used to develop the 10-day average total sulfur-to-H_2S concentration ratio, unitless.

(vii) For each day during the period when data are being collected to develop a 10-day average, the owner or operator shall estimate the total sulfur concentration using the measured total sulfur concentration measured for that day.

(viii) For all days other than those during which data are being collected to develop a 10-day average, the owner or operator shall multiply the most recent 10-day average total sulfur-to-H_2S ratio by the daily average H_2S concentrations obtained using the monitor as required by paragraph (e)(2)(i) through (iii) of this section to estimate total sulfur concentrations.

(ix) If the total sulfur-to-H_2S ratio for a subsequent weekly sample is outside the acceptable range for the most recent distribution of daily ratios, the owner or operator shall develop a new 10-day average ratio and acceptable range based on data for the outlying weekly sample plus data collected over the following 9 operating days.

(3) *SO_2 monitoring requirements.* The owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of SO_2 from a process heater or other fuel gas combustion device that is combusting gas representative of the fuel gas in the flare gas line according to the requirements in paragraph (a)(1) of this section, determine the F factor of the fuel gas at least daily according to the requirements in paragraphs (d)(2) through (4) of this section, determine the higher heating value of the fuel gas at least daily according to the requirements in paragraph (d)(7) of this section, and calculate the total sulfur content (as SO_2) in the fuel gas using Equation 15 of this section.

$$TS_{FG} = C_{SO_2} \times F_d \times HHV_{FG} \qquad \text{(Eq. 15)}$$

Where:

TS_{FG} = Total sulfur concentration, as SO_2, in the fuel gas, ppmv.

C_{SO2} = Concentration of SO_2 in the exhaust gas, ppmv (dry basis at 0-percent excess air).

F_d = F factor gas on dry basis at 0-percent excess air, dscf/MMBtu.

HHV_{FG} = Higher heating value of the fuel gas, MMBtu/scf.

(4) *Exemptions from sulfur monitoring requirements.* Flares identified in paragraphs (e)(4)(i) through (iv) of this section are exempt from the requirements in paragraphs (e)(1) through (3) of this section. For each such flare, except as provided in paragraph (e)(4)(iv), engineering calculations shall be used to calculate the SO_2 emissions in the event of a discharge that may trigger a root cause analysis under §60.103a(c)(1).

(i) Flares that can only receive:

(A) Fuel gas streams that are inherently low in sulfur content as described in paragraph (a)(3)(i) through (iv) of this section; and/or

(B) Fuel gas streams that are inherently low in sulfur content for which the owner or operator has applied for an exemption from the H_2S monitoring requirements as described in paragraph (b) of this section.

(ii) Emergency flares, provided that for each such flare, the owner or operator complies with the monitoring alternative in paragraph (g) of this section.

(iii) Flares equipped with flare gas recovery systems designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction, provided that for each such flare, the owner or operator complies with the monitoring alternative in paragraph (g) of this section.

(iv) Secondary flares that receive gas diverted from the primary flare. In the event of a discharge from the secondary flare, the sulfur content measured by the sulfur monitor on the primary flare should be used to calculate SO_2 emissions, regardless of whether or not the monitoring alternative in paragraph (g) of this section is selected for the secondary flare.

(f) *Flow monitoring for flares.* Except as provided in paragraphs (f)(2) and (h) of this section, the owner or operator of an affected flare subject to §60.103a(c) through (e) shall install, operate, calibrate and maintain, in accordance with the specifications in paragraph (f)(1) of this section, a CPMS to measure and record the flow rate of gas discharged to the flare. If a flow monitor is not already in place, the owner or operator of a modified flare shall comply with the requirements of this paragraph by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) The owner or operator shall install, calibrate, operate and maintain each flow monitor according to the manufacturer's procedures and specifications and the following requirements.

(i) Locate the monitor in a position that provides a representative measurement of the total gas flow rate.

(ii) Use a flow sensor meeting an accuracy requirement of ±20 percent of the flow rate at velocities ranging from 0.1 to 1 feet per second and an accuracy of ±5 percent of the flow rate for velocities greater than 1 feet per second.

(iii) Use a flow monitor that is maintainable online, is able to continuously correct for temperature and pressure and is able to record flow in standard conditions (as defined in §60.2) over one-minute averages.

(iv) At least quarterly, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if the flow monitor is not equipped with a redundant flow sensor.

(v) Recalibrate the flow monitor in accordance with the manufacturer's procedures and specifications biennially (every two years) or at the frequency specified by the manufacturer.

(2) Emergency flares, secondary flares and flares equipped with flare gas recovery systems designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction are not required to install continuous flow monitors; provided, however, that for any such flare, the owner or operator shall comply with the monitoring alternative in paragraph (g) of this section.

(g) *Alternative monitoring for certain flares equipped with water seals.* The owner or operator of an affected flare subject to §60.103a(c) through (e) that can be classified as either an emergency flare, a secondary flare or a flare equipped with a flare gas recovery system designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction may, as an alternative to the sulfur and flow monitoring requirements of paragraphs (e) and (f) of this section, install, operate, calibrate and maintain, in accordance with the requirements in paragraphs (g)(1) through (7) of this section, a CPMS to measure and record the pressure in the flare gas header between the knock-out pot and water seal and to measure and record the water seal liquid level. If the required monitoring systems are not already in place, the owner or operator of a modified flare shall comply with the requirements of this paragraph by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and locate the liquid seal level monitor in a position that provides a representative measurement of the water column height.

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

(3) Use a pressure sensor and level monitor with a minimum tolerance of 1.27 centimeters of water.

(4) Using a manometer, check pressure sensor calibration quarterly.

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

(6) In a cascaded flare system that employs multiple secondary flares, pressure and liquid level monitoring is required only on the first secondary flare in the system (*i.e.,* the secondary flare with the lowest pressure release set point).

(7) This alternative monitoring option may be elected only for flares with four or fewer pressure exceedances required to be reported under §60.108a(d)(5) ("reportable pressure exceedances") in any 365 consecutive calendar days. Following the fifth reportable pressure exceedance in a 365-day period, the owner or operator must comply with the sulfur and flow monitoring requirements of paragraphs (e) and (f) of this section as soon as practical, but no later than 180 days after the fifth reportable pressure exceedance in a 365-day period.

(h) *Alternative monitoring for flares located in the BAAQMD or SCAQMD.* An affected flare subject to this subpart located in the BAAQMD may elect to comply with the monitoring requirements in both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (e) and (f) of this section. An affected flare subject to this subpart located in the SCAQMD may elect to comply with the monitoring requirements in SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (e) and (f) of this section.

(i) *Excess emissions.* For the purpose of reports required by §60.7(c), periods of excess emissions for fuel gas combustion devices subject to the emissions limitations in §60.102a(g) and flares subject to the concentration requirement in §60.103a(h) are defined as specified in paragraphs (i)(1) through (5) of this section. Determine a rolling 3-hour or a rolling daily average as the arithmetic average of the applicable 1-hour averages (e.g., a rolling 3-hour average is the arithmetic average of three contiguous 1-hour averages). Determine a rolling 30-day or a rolling 365-day average as the arithmetic average of the applicable daily averages (e.g., a rolling 30-day average is the arithmetic average of 30 contiguous daily averages).

(1) *SO_2 or H_2S limits for fuel gas combustion devices.* (i) If the owner or operator of a fuel gas combustion device elects to comply with the SO_2 emission limits in §60.102a(g)(1)(i), each rolling 3-hour period during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system required under paragraph (a)(1) of this section exceeds 20 ppmv, and each rolling 365-day period during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system required under paragraph (a)(1) of this section exceeds 8 ppmv.

(ii) If the owner or operator of a fuel gas combustion device elects to comply with the H_2S concentration limits in §60.102a(g)(1)(ii), each rolling 3-hour period during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H_2S continuous monitoring system under paragraph (a)(2) of this section exceeds 60 ppmv.

(iii) If the owner or operator of a fuel gas combustion device becomes subject to the requirements of daily stain tube sampling in paragraph (b)(3)(iii) of this section, each day during which the daily concentration of H_2S exceeds 162 ppmv and each rolling 365-day period during which the average concentration of H_2S exceeds 60 ppmv.

(2) H_2S concentration limits for flares. (i) Each rolling 3-hour period during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv.

(ii) If the owner or operator of a flare becomes subject to the requirements of daily stain tube sampling in paragraph (b)(3)(iii) of this section, each day during which the daily concentration of H_2S exceeds 162 ppmv.

(3) *Rolling 30-day average NO_X limits for fuel gas combustion devices.* Each rolling 30-day period during which the average concentration of NO_X as measured by the NO_X continuous monitoring system required under paragraph (c) or (d) of this section exceeds:

(i) For a natural draft process heater, 40 ppmv and, if monitored according to §60.107a(d), 0.040 lb/MMBtu;

(ii) For a forced draft process heater, 60 ppmv and, if monitored according to §60.107a(d), 0.060 lb/MMBtu; and

(iii) For a co-fired process heater electing to comply with the NO_X limit in §60.102a(g)(2)(iii)(A) or (g)(2)(iv)(A), 150 ppmv.

(iv) The site-specific limit determined by the Administrator under §60.102a(i).

(4) *Daily NO_X limits for fuel gas combustion devices.* Each day during which the concentration of NO_X as measured by the NO_X continuous monitoring system required under paragraph (d) of this section exceeds the daily average emissions limit calculated using Equation 3 in §60.102a(g)(2)(iii)(B) or Equation 4 in §60.102a(g)(2)(iv)(B).

(5) *Daily O_2 limits for fuel gas combustion devices.* Each day during which the concentration of O_2 as measured by the O_2 continuous monitoring system required under paragraph (c)(6) or (d)(8) of this section exceeds the O_2 operating limit or operating curve determined during the most recent biennial performance test.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56473, Sep. 12, 2012; 80 FR 75235, Dec. 1, 2015]

§60.108a Recordkeeping and reporting requirements.

(a) Each owner or operator subject to the emissions limitations in §60.102a shall comply with the notification, recordkeeping, and reporting requirements in §60.7 and other requirements as specified in this section.

(b) Each owner or operator subject to an emissions limitation in §60.102a shall notify the Administrator of the specific monitoring provisions of §§60.105a, 60.106a and 60.107a with which the owner or operator intends to comply. Each owner or operator of a co-fired process heater subject to an emissions limitation in §60.102a(g)(2)(iii) or (iv) shall submit to the Administrator documentation showing that the process heater meets the definition of a co-fired process heater in §60.101a. Notifications required by this paragraph shall be submitted with the notification of initial startup required by §60.7(a)(3).

(c) The owner or operator shall maintain the following records:

(1) A copy of the flare management plan.

(2) Records of information to document conformance with bag leak detection system operation and maintenance requirements in §60.105a(c).

(3) Records of bag leak detection system alarms and actions according to §60.105a(c).

(4) For each FCCU and fluid coking unit subject to the monitoring requirements in §60.105a(b)(1), records of the average coke burn-off rate and hours of operation.

(5) For each fuel gas stream to which one of the exemptions listed in §60.107a(a)(3) applies, records of the specific exemption determined to apply for each fuel stream. If the owner or operator applies for the exemption described in §60.107a(a)(3)(iv), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application.

(6) Records of discharges greater than 500 lb SO_2 in any 24-hour period from any affected flare, discharges greater than 500 lb SO_2 in excess of the allowable limits from a fuel gas combustion device or sulfur recovery plant and discharges to an affected flare in excess of 500,000 scf above baseline in any 24-hour period as required by §60.103a(c). If the monitoring alternative provided in §60.107a(g) is selected, the owner or operator shall record any instance when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in §60.103a(a)(3)(vii)(C). The following information shall be recorded no later than 45 days following the end of a discharge exceeding the thresholds:

(i) A description of the discharge.

(ii) The date and time the discharge was first identified and the duration of the discharge.

(iii) The measured or calculated cumulative quantity of gas discharged over the discharge duration. If the discharge duration exceeds 24 hours, record the discharge quantity for each 24-hour period. For a flare, record the measured or calculated cumulative quantity of gas discharged to the flare over the discharge duration. If the discharge duration exceeds 24 hours, record the quantity of gas discharged to the flare for each 24-hour period. Engineering calculations are allowed for fuel gas combustion devices, but are not allowed for flares, except for those complying with the alternative monitoring requirements in §60.107a(g).

(iv) For each discharge greater than 500 lb SO_2 in any 24-hour period from a flare, the measured total sulfur concentration or both the measured H_2S concentration and the estimated total sulfur concentration in the fuel gas at a representative location in the flare inlet.

(v) For each discharge greater than 500 lb SO_2 in excess of the applicable short-term emissions limit in §60.102a(g)(1) from a fuel gas combustion device, either the measured concentration of H_2S in the fuel gas or the measured concentration of SO_2 in the stream discharged to the atmosphere. Process knowledge can be used to make these estimates for fuel gas combustion devices, but cannot be used to make these estimates for flares, except as provided in §60.107a(e)(4).

(vi) For each discharge greater than 500 lb SO_2 in excess of the allowable limits from a sulfur recovery plant, either the measured concentration of reduced sulfur or SO_2 discharged to the atmosphere.

(vii) For each discharge greater than 500 lb SO_2 in any 24-hour period from any affected flare or discharge greater than 500 lb SO_2 in excess of the allowable limits from a fuel gas combustion device or sulfur recovery plant, the cumulative quantity of H_2S and SO_2 released into the atmosphere. For releases controlled by flares, assume 99-percent conversion of reduced sulfur or total sulfur to SO_2. For fuel gas combustion devices, assume 99-percent conversion of H_2S to SO_2.

(viii) The steps that the owner or operator took to limit the emissions during the discharge.

(ix) The root cause analysis and corrective action analysis conducted as required in §60.103a(d), including an identification of the affected facility, the date and duration of the discharge, a statement noting whether the discharge resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under §60.103a(e).

(x) For any corrective action analysis for which corrective actions are required in §60.103a(e), a description of the corrective action(s) completed within the first 45 days following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(xi) For each discharge from any affected flare that is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare, a statement that a root cause analysis and corrective action analysis are not necessary because the owner or operator followed the flare management plan.

(7) If the owner or operator elects to comply with §60.107a(e)(2) for a flare, records of the H_2S and total sulfur analyses of each grab or integrated sample, the calculated daily total sulfur-to-H_2S ratios, the calculated 10-day average total sulfur-to-H_2S ratios and the 95-percent confidence intervals for each 10-day average total sulfur-to-H_2S ratio.

(d) Each owner or operator subject to this subpart shall submit an excess emissions report for all periods of excess emissions according to the requirements of §60.7(c) except that the report shall contain the information specified in paragraphs (d)(1) through (7) of this section.

(1) The date that the exceedance occurred;

(2) An explanation of the exceedance;

(3) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system; and

(4) A description of the action taken, if any.

(5) The information described in paragraph (c)(6) of this section for all discharges listed in paragraph (c)(6) of this section. For a flare complying with the monitoring alternative under §60.107a(g), following the fifth discharge required to be recorded under paragraph (c)(6) of this section and reported under this paragraph, the owner or operator shall include notification that monitoring systems will be installed according to §60.107a(e) and (f) within 180 days following the fifth discharge.

(6) For any periods for which monitoring data are not available, any changes 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.

(7) A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56479, Sep. 12, 2012]

§60.109a Delegation of authority.

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

(b) In delegating implementation and enforcement authority of this subpart to a state, local or tribal agency, the approval authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the state, local or tribal agency.

(1) Approval of a major change to test methods under §60.8(b). A “major change to test method” is defined in 40 CFR 63.90.

(2) Approval of a major change to monitoring under §60.13(i). A “major change to monitoring” is defined in 40 CFR 63.90.

(3) Approval of a major change to recordkeeping/reporting under §60.7(b) through (f). A “major change to recordkeeping/reporting” is defined in 40 CFR 63.90.

(4) Approval of an application for an alternative means of emission limitation under §60.103a(j) of this subpart.

[73 FR 35867, June 24, 2008, as amended at 77 FR 56480, Sep. 12, 2012]

Table 1 to Subpart Ja of Part 60—Molar Exhaust Volumes and Molar Heat Content of Fuel Gas Constituents

Constituent	**MEV[a] dscf/mol**	**MHC[b] Btu/mol**
Methane (CH_4)	7.29	842
Ethane (C_2H_6)	12.96	1,475
Hydrogen (H_2)	1.61	269
Ethene (C_2H_4)	11.34	1,335
Propane (C_3H_8)	18.62	2,100
Propene (C_3H_6)	17.02	1,947
Butane (C_4H_{10})	24.30	2,717
Butene (C_4H_8)	22.69	2,558
Inerts	0.85	0

[a] MEV = molar exhaust volume, dry standard cubic feet per gram-mole (dscf/g-mol) at standard conditions of 68 °F and 1 atmosphere.

[b] MHC = molar heat content (higher heating value basis), Btu per gram-mole (Btu/g-mol).

[77 FR 56480, Sep. 12, 2012]

Attachment E

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on May 13, 2013]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

SOURCE: 52 FR 11429, Apr. 8, 1987, unless otherwise noted.

§ 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 (m^3) 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 151 m^3 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, railcars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 m^3 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 m^3 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 m^3 but less than 151 m^3 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).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 78275, Dec. 14, 2000; 68 FR 59332, Oct. 15, 2003]

§ 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 described 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 D2879-83, 96, or 97 (incorporated by reference—see § 60.17);

(4) Any other method approved by the Administrator.

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.

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).

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; 65 FR 61756, Oct. 17, 2000; 68 FR 59333, Oct. 15, 2003]

§ 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 m^3 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 m^3 but less than 151 m^3 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.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in § 60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in § 60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents 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. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(3) A closed vent system and control device meeting the following specifications:

(i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, § 60.485(b).

(ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§ 60.18) of the General Provisions.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in § 60.114b of this subpart.

(b) The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m^3 which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in § 60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in § 60.114b of this subpart.

(c) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia (“site”).

(1) For any storage vessel that otherwise would be subject to the control technology requirements of paragraphs (a) or (b) of this section, the site shall have the option of either complying directly with the requirements of this subpart, or reducing the site-wide total criteria pollutant emissions cap (total emissions cap) in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the total emissions cap in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this subpart for such storage vessel.

(2) For any storage vessel at the site not subject to the requirements of 40 CFR 60.112b (a) or (b), the requirements of 40 CFR 60.116b (b) and (c) and the General Provisions (subpart A of this part) shall not apply.

[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.

(b) After installing the control equipment required to meet § 60.112b(a)(2) (external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4) (i) and (ii) of this section:

(i) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212 Cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of § 60.113b(b) 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(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external 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, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of 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.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in § 60.112b (a)(3) or (b)(2) (other than a flare) is exempt from § 60.8 of the General Provisions and shall meet the following requirements.

(1) Submit for approval by the Administrator as an attachment to the notification required by § 60.7(a)(1) or, if the facility is exempt from § 60.7(a)(1), as an attachment to the notification required by § 60.7(a)(2), an operating plan containing the information listed below.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in § 60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, § 60.18 (e) and (f).

[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.

(b) After installing control equipment in accordance with § 61.112b(a)(2) (external 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)(2) and § 60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by § 60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by § 60.113b(b)(1), furnish the Administrator with a report that contains:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in § 60.113b (b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by § 60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in § 60.113b (b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by § 60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.

(c) After installing control equipment in accordance with § 60.112b (a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

(1) A copy of the operating plan.

(2) A record of the measured values of the parameters monitored in accordance with § 60.113b(c)(2).

(d) After installing a closed vent system and flare to comply with § 60.112b, the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by § 60.18(f) (1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by § 60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under § 60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

§ 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 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 D2879-83, 96, or 97 (incorporated by reference—see § 60.17); or

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

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

(g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of § 60.112b or with emissions reductions equipment as specified in 40 CFR 65.42(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.

[52 FR 11429, Apr. 8, 1987, as amended at 65 FR 61756, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000; 68 FR 59333, Oct. 15, 2003]

§ 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]

Attachment F

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on May 13, 2013]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart Y—Standards of Performance for Coal Preparation and Processing Plants

Source: 74 FR 51977, Oct. 8, 2009, unless otherwise noted.

§ 60.250 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to affected facilities in coal preparation and processing plants that process more than 181 megagrams (Mg) (200 tons) of coal per day.

(b) The provisions in § 60.251, § 60.252(a), § 60.253(a), § 60.254(a), § 60.255(a), and § 60.256(a) of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after October 27, 1974, and on or before April 28, 2008: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems, transfer and loading systems.

(c) The provisions in § 60.251, § 60.252(b)(1) and (c), § 60.253(b), § 60.254(b), § 60.255(b) through (h), § 60.256(b) and (c), § 60.257, and § 60.258 of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after April 28, 2008, and on or before May 27, 2009: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems, transfer and loading systems.

(d) The provisions in § 60.251, § 60.252(b)(1) through (3), and (c), § 60.253(b), § 60.254(b) and (c), § 60.255(b) through (h), § 60.256(b) and (c), § 60.257, and § 60.258 of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after May 27, 2009: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, transfer and loading systems, and open storage piles.

§ 60.251 Definitions.

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

(a) *Anthracite* means coal that is classified as anthracite according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, *see* § 60.17).

(b) *Bag leak detection system* means a system that is capable of continuously monitoring relative particulate matter (dust loadings) in the exhaust of a fabric filter to detect bag leaks and other upset conditions. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, light scattering, light transmittance, or other effect to continuously monitor relative particulate matter loadings.

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

(d) *Coal* means:

(1) For units constructed, reconstructed, or modified on or before May 27, 2009, all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference— *see* § 60.17).

(2) For units constructed, reconstructed, or modified after May 27, 2009, all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference— *see* § 60.17), and coal refuse.

(e) *Coal preparation and processing plant* means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

(f) *Coal processing and conveying equipment* means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts. Equipment located at the mine face is not considered to be part of the coal preparation and processing plant.

(g) *Coal refuse* means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, *etc.*) containing coal, matrix material, clay, and other organic and inorganic material.

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

(i) *Design controlled potential PM emissions rate* means the theoretical particulate matter (PM) emissions (Mg) that would result from the operation of a control device at its design emissions rate (grams per dry standard cubic meter (g/dscm)), multiplied by the maximum design flow rate (dry standard cubic meter per minute (dscm/min)), multiplied by 60 (minutes per hour (min/hr)), multiplied by 8,760 (hours per year (hr/yr)), divided by 1,000,000 (megagrams per gram (Mg/g)).

(j) *Indirect thermal dryer* means a thermal dryer that reduces the moisture content of coal through indirect heating of the coal through contact with a heat transfer medium. If the source of heat (the source of combustion or furnace) is subject to another subpart of this part, then the furnace and the associated emissions are not part of the affected facility. However, if the source of heat is not subject to another subpart of this part, then the furnace and the associated emissions are part of the affected facility.

(k) *Lignite* means coal that is classified as lignite A or B according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, *see* § 60.17).

(l) *Mechanical vent* means any vent that uses a powered mechanical drive (machine) to induce air flow.

(m) *Open storage pile* means any facility, including storage area, that is not enclosed that is used to store coal, including the equipment used in the loading, unloading, and conveying operations of the facility.

(n) *Operating day* means a 24-hour period between 12 midnight and the following midnight during which coal is prepared or processed at any time by the affected facility. It is not necessary that coal be prepared or processed the entire 24-hour period.

(o) *Pneumatic coal-cleaning equipment* means:

(1) For units constructed, reconstructed, or modified on or before May 27, 2009, any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(2) For units constructed, reconstructed, or modified after May 27, 2009, any facility which classifies coal by size or separates coal from refuse by application of air stream(s).

(p) *Potential combustion concentration* means the theoretical emissions (nanograms per joule (ng/J) or pounds per million British thermal units (lb/MMBtu) heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems, as determined using Method 19 of appendix A-7 of this part.

(q) *Subbituminous coal* means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, *see* § 60.17).

(r) *Thermal dryer* means:

(1) For units constructed, reconstructed, or modified on or before May 27, 2009, any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

(2) For units constructed, reconstructed, or modified after May 27, 2009, any facility in which the moisture content of coal is reduced by either contact with a heated gas stream which is exhausted to the atmosphere or through indirect heating of the coal through contact with a heated heat transfer medium.

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

§ 60.252 Standards for thermal dryers.

(a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified on or before April 28, 2008, subject to the provisions of this subpart must meet the requirements in paragraphs (a)(1) and (a)(2) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer any gases which contain PM in excess of 0.070 g/dscm (0.031 grains per dry standard cubic feet (gr/dscf)); and

(2) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer any gases which exhibit 20 percent opacity or greater.

(b) Except as provided in paragraph (c) of this section, on and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified after April 28, 2008, subject to the provisions of this subpart must meet the applicable standards for PM and opacity, as specified in paragraph (b)(1) of this section. In addition, and except as provided in paragraph (c) of this section, on and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified after May 29, 2009, subject to the provisions of this subpart must also meet the applicable standards for sulfur dioxide (SO_2), and combined nitrogen oxides (NO_X) and carbon monoxide (CO) as specified in paragraphs (b)(2) and (b)(3) of this section.

(1) The owner or operator must meet the requirements for PM emissions in paragraphs (b)(1)(i) through (iii) of this section, as applicable to the affected facility.

(i) For each thermal dryer constructed or reconstructed after April 28, 2008, the owner or operator must meet the requirements of (b)(1)(i)(A) and (b)(1)(i)(B).

(A) The owner or operator must not cause to be discharged into the atmosphere from the thermal dryer any gases that contain PM in excess of 0.023 g/dscm (0.010 grains per dry standard cubic feet (gr/dscf)); and

(B) The owner or operator must not cause to be discharged into the atmosphere from the thermal dryer any gases that exhibit 10 percent opacity or greater.

(ii) For each thermal dryer modified after April 28, 2008, the owner or operator must meet the requirements of paragraphs (b)(1)(ii)(A) and (b)(1)(ii)(B) of this section.

(A) The owner or operator must not cause to be discharged to the atmosphere from the affected facility any gases which contain PM in excess of 0.070 g/dscm (0.031 gr/dscf); and

(B) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which exhibit 20 percent opacity or greater.

(2) Except as provided in paragraph (b)(2)(iii) of this section, for each thermal dryer constructed, reconstructed, or modified after May 27, 2009, the owner or operator must meet the requirements for SO_2 emissions in either paragraph (b)(2)(i) or (b)(2)(ii) of this section.

(i) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 85 ng/J (0.20 lb/MMBtu) heat input; or

(ii) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases that either contain SO_2 in excess of 520 ng/J (1.20 lb/MMBtu) heat input or contain SO_2 in excess of 10 percent of the potential combustion concentration (*i.e.,* the facility must achieve at least a 90 percent reduction of the potential combustion concentration and may not exceed a maximum emissions rate of 1.2 lb/MMBtu (520 ng/J)).

(iii) Thermal dryers that receive all of their thermal input from a source other than coal or residual oil, that receive all of their thermal input from a source subject to an SO_2 limit under another subpart of this part, or that use waste heat or residual from the combustion of coal or residual oil as their only thermal input are not subject to the SO_2 limits of this section.

(3) Except as provided in paragraph (b)(3)(iii) of this section, the owner or operator must meet the requirements for combined NO_X and CO emissions in paragraph (b)(3)(i) or (b)(3)(ii) of this section, as applicable to the affected facility.

(i) For each thermal dryer constructed after May 27, 2009, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which contain a combined concentration of NO_X and CO in excess of 280 ng/J (0.65 lb/MMBtu) heat input.

(ii) For each thermal dryer reconstructed or modified after May 27, 2009, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which contain combined concentration of NO_X and CO in excess of 430 ng/J (1.0 lb/MMBtu) heat input.

(iii) Thermal dryers that receive all of their thermal input from a source other than coal or residual oil, that receive all of their thermal input from a source subject to a NO_X limit and/or CO limit under another subpart of this part, or that use waste heat or residual from the combustion of coal or residual oil as their only thermal input, are not subject to the combined NO_X and CO limits of this section.

(c) Thermal dryers receiving all of their thermal input from an affected facility covered under another 40 CFR Part 60 subpart must meet the applicable requirements in that subpart but are not subject to the requirements in this subpart.

§ 60.253 Standards for pneumatic coal-cleaning equipment.

(a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of pneumatic coal-cleaning equipment constructed, reconstructed, or modified on or before April 28, 2008, must meet the requirements of paragraphs (a)(1) and (a)(2) of this section.

(1) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that contain PM in excess of 0.040 g/dscm (0.017 gr/dscf); and

(2) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that exhibit 10 percent opacity or greater.

(b) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of pneumatic coal-cleaning equipment constructed, reconstructed, or modified after April 28, 2008, must meet the requirements in paragraphs (b)(1) and (b)(2) of this section.

(1) The owner of operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that contain PM in excess or 0.023 g/dscm (0.010 gr/dscf); and

(2) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that exhibit greater than 5 percent opacity.

§ 60.254 Standards for coal processing and conveying equipment, coal storage systems, transfer and loading systems, and open storage piles.

(a) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal constructed, reconstructed, or modified on or before April 28, 2008, gases which exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test is conducted or required to be completed under § 60.8, whichever date comes first, an owner or operator of any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal constructed, reconstructed, or modified after April 28, 2008, must meet the requirements in paragraphs (b)(1) through (3) of this section, as applicable to the affected facility.

(1) Except as provided in paragraph (b)(3) of this section, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which exhibit 10 percent opacity or greater.

(2) The owner or operator must not cause to be discharged into the atmosphere from any mechanical vent on an affected facility gases which contain particulate matter in excess of 0.023 g/dscm (0.010 gr/dscf).

(3) Equipment used in the loading, unloading, and conveying operations of open storage piles are not subject to the opacity limitations of paragraph (b)(1) of this section.

(c) The owner or operator of an open storage pile, which includes the equipment used in the loading, unloading, and conveying operations of the affected facility, constructed, reconstructed, or modified after May 27, 2009, must prepare and operate in accordance with a submitted fugitive coal dust emissions control plan that is appropriate for the site conditions as specified in paragraphs (c)(1) through (6) of this section.

(1) The fugitive coal dust emissions control plan must identify and describe the control measures the owner or operator will use to minimize fugitive coal dust emissions from each open storage pile.

(2) For open coal storage piles, the fugitive coal dust emissions control plan must require that one or more of the following control measures be used to minimize to the greatest extent practicable fugitive coal dust: Locating the source inside a partial enclosure, installing and operating a water spray or fogging system, applying appropriate chemical dust suppression agents on the source (when the provisions of paragraph (c)(6) of this section are met), use of a wind barrier, compaction, or use of a vegetative cover. The owner or operator must select, for inclusion in the fugitive coal dust emissions control plan, the control measure or measures listed in this paragraph that are most appropriate for site conditions. The plan must also explain how the measure or measures selected are applicable and appropriate for site conditions. In addition, the plan must be revised as needed to reflect any changing conditions at the source.

(3) Any owner or operator of an affected facility that is required to have a fugitive coal dust emissions control plan may petition the Administrator to approve, for inclusion in the plan for the affected facility, alternative control measures other than those specified in paragraph (c)(2) of this section as specified in paragraphs (c)(3)(i) through (iv) of this section.

(i) The petition must include a description of the alternative control measures, a copy of the fugitive coal dust emissions control plan for the affected facility that includes the alternative control measures, and information sufficient for EPA to evaluate the demonstrations required by paragraph (c)(3)(ii) of this section.

(ii) The owner or operator must either demonstrate that the fugitive coal dust emissions control plan that includes the alternate control measures will provide equivalent overall environmental protection or demonstrate that it is either economically or technically infeasible for the affected facility to use the control measures specifically identified in paragraph (c)(2).

(iii) While the petition is pending, the owner or operator must comply with the fugitive coal dust emissions control plan including the alternative control measures submitted with the petition. Operation in accordance with the plan submitted with the petition shall be deemed to constitute compliance with the requirement to operate in accordance with a fugitive coal dust emissions control plan that contains one of the control measures specifically identified in paragraph (c)(2) of this section while the petition is pending.

(iv) If the petition is approved by the Administrator, the alternative control measures will be approved for inclusion in the fugitive coal dust emissions control plan for the affected facility. In lieu of amending this subpart, a letter will be sent to the facility describing the specific control measures approved. The facility shall make any such letters and the applicable fugitive coal dust emissions control plan available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(4) The owner or operator must submit the fugitive coal dust emissions control plan to the Administrator or delegated authority as specified in paragraphs (c)(4)(i) and (c)(4)(ii) of this section.

(i) The plan must be submitted to the Administrator or delegated authority prior to startup of the new, reconstructed, or modified affected facility, or 30 days after the effective date of this rule, whichever is later.

(ii) The plan must be revised as needed to reflect any changing conditions at the source. Such revisions must be dated and submitted to the Administrator or delegated authority before a source can operate pursuant to these revisions. The Administrator or delegated authority may also object to such revisions as specified in paragraph (c)(5) of this section.

(5) The Administrator or delegated authority may object to the fugitive coal dust emissions control plan as specified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.

(i) The Administrator or delegated authority may object to any fugitive coal dust emissions control plan that it has determined does not meet the requirements of paragraphs (c)(1) and (c)(2) of this section.

(ii) If an objection is raised, the owner or operator, within 30 days from receipt of the objection, must submit a revised fugitive coal dust emissions control plan to the Administrator or delegated authority. The owner or operator must operate in accordance with the revised fugitive coal dust emissions control plan. The Administrator or delegated authority retain the right, under paragraph (c)(5) of this section, to object to the revised control plan if it determines the plan does not meet the requirements of paragraphs (c)(1) and (c)(2) of this section.

(6) Where appropriate chemical dust suppression agents are selected by the owner or operator as a control measure to minimize fugitive coal dust emissions, (1) only chemical dust suppressants with Occupational Safety and Health Administration (OSHA)-compliant material safety data sheets (MSDS) are to be allowed; (2) the MSDS must be included in the fugitive coal dust emissions control plan; and (3) the owner or operator must consider and document in the fugitive coal dust emissions control plan the site-specific impacts associated with the use of such chemical dust suppressants.

§ 60.255 Performance tests and other compliance requirements.

(a) An owner or operator of each affected facility that commenced construction, reconstruction, or modification on or before April 28, 2008, must conduct all performance tests required by § 60.8 to demonstrate compliance with the applicable emission standards using the methods identified in § 60.257.

(b) An owner or operator of each affected facility that commenced construction, reconstruction, or modification after April 28, 2008, must conduct performance tests according to the requirements of § 60.8 and the methods identified in § 60.257 to demonstrate compliance with the applicable emissions standards in this subpart as specified in paragraphs (b)(1) and (2) of this section.

(1) For each affected facility subject to a PM, SO_2 , or combined NO_X and CO emissions standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according the requirements in paragraphs (b)(1)(i) through (iii) of this section, as applicable.

(i) If the results of the most recent performance test demonstrate that emissions from the affected facility are greater than 50 percent of the applicable emissions standard, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.

(ii) If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed.

(iii) An owner or operator of an affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 30 calendar days after the next operating day.

(2) For each affected facility subject to an opacity standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according to the requirements in paragraphs (b)(2)(i) through (iii) of this section, as applicable, except as provided for in paragraphs (e) and (f) of this section. Performance test and other compliance requirements for coal truck dump operations are specified in paragraph (h) of this section.

(i) If any 6-minute average opacity reading in the most recent performance test exceeds half the applicable opacity limit, a new performance test must be conducted within 90 operating days of the date that the previous performance test was required to be completed.

(ii) If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.

(iii) An owner or operator of an affected facility continuously monitoring scrubber parameters as specified in § 60.256(b)(2) is exempt from the requirements in paragraphs (b)(2)(i) and (ii) if opacity performance tests are conducted concurrently with (or within a 60-minute period of) PM performance tests.

(c) If any affected coal processing and conveying equipment (*e.g.,* breakers, crushers, screens, conveying systems), coal storage systems, or coal transfer and loading systems that commenced construction, reconstruction, or modification after April 28, 2008, are enclosed in a building, and emissions from the building do not exceed any of the standards in § 60.254 that apply to the affected facility, then the facility shall be deemed to be in compliance with such standards.

(d) An owner or operator of an affected facility (other than a thermal dryer) that commenced construction, reconstruction, or modification after April 28, 2008, is subject to a PM emission standard and uses a control device with a design controlled potential PM emissions rate of 1.0 Mg (1.1 tons) per year or less is exempted from the requirements of paragraphs (b)(1)(i) and (ii) of this section provided that the owner or operator meets all of the conditions specified in paragraphs (d)(1) through (3) of this section. This exemption does not apply to thermal dryers.

(1) PM emissions, as determined by the most recent performance test, are less than or equal to the applicable limit,

(2) The control device manufacturer's recommended maintenance procedures are followed, and

(3) All 6-minute average opacity readings from the most recent performance test are equal to or less than half the applicable opacity limit or the monitoring requirements in paragraphs (e) or (f) of this section are followed.

(e) For an owner or operator of a group of up to five of the same type of affected facilities that commenced construction, reconstruction, or modification after April 28, 2008, that are subject to PM emissions standards and use identical control devices, the Administrator or delegated authority may allow the owner or operator to use a single PM performance test for one of the affected control devices to demonstrate that the group of affected facilities is in compliance with the applicable emissions standards provided that the owner or operator meets all of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) PM emissions from the most recent performance test for each individual affected facility are 90 percent or less of the applicable PM standard;

(2) The manufacturer's recommended maintenance procedures are followed for each control device; and

(3) A performance test is conducted on each affected facility at least once every 5 calendar years.

(f) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, may elect to comply with the requirements in paragraph (f)(1) or (f)(2) of this section.

(1) Monitor visible emissions from each affected facility according to the requirements in paragraphs (f)(1)(i) through (iii) of this section.

(i) Conduct one daily 15-second observation each operating day for each affected facility (during normal operation) when the coal preparation and processing plant is in operation. Each observation must be recorded as either visible emissions observed or no visible emissions observed. Each observer determining the presence of visible emissions must meet the training requirements specified in § 2.3 of Method 22 of appendix A-7 of this part. If visible emissions are observed during any 15-second observation, the owner or operator must adjust the operation of the affected facility and demonstrate within 24 hours that no visible emissions are observed from the affected facility. If visible emissions are observed, a Method 9, of appendix A-4 of this part, performance test must be conducted within 45 operating days.

(ii) Conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible.

(iii) Conduct a performance test using Method 9 of appendix A-4 of this part at least once every 5 calendar years for each affected facility.

(2) Prepare a written site-specific monitoring plan for a digital opacity compliance system for approval by the Administrator or delegated authority. The plan shall require observations of at least one digital image every 15 seconds for 10-minute periods (during normal operation) every operating day. An approvable monitoring plan must include a demonstration that the occurrences of visible emissions are not in excess of 5 percent of the observation period. For reference purposes in preparing the monitoring plan, *see* OAQPS “Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods. The monitoring plan approved by the Administrator or delegated authority shall be implemented by the owner or operator.

(g) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, subject to a visible emissions standard under this subpart may install, operate, and maintain a continuous opacity monitoring system (COMS). Each COMS used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (g)(1) and (2) of this section.

(1) The COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B.

(2) The COMS must comply with the quality assurance requirements in paragraphs (g)(2)(i) through (v) of this section.

(i) The owner or operator must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in 40 CFR part 60, appendix B.

(ii) The owner or operator must adjust the zero and span whenever the 24-hour zero drift or 24-hour span drift exceeds 4 percent opacity. The COMS must allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified. The optical surfaces exposed to the effluent gases must be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments. For systems using automatic zero adjustments, the optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(iii) The owner or operator must apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. All procedures applied must provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(iv) Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS must be in continuous operation and 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.

(v) The owner or operator must reduce all data from the COMS to 6-minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments must not be included in the data averages. An arithmetic or integrated average of all data may be used.

(h) The owner or operator of each affected coal truck dump operation that commenced construction, reconstruction, or modification after April 28, 2008, must meet the requirements specified in paragraphs (h)(1) through (3) of this section.

(1) Conduct an initial performance test using Method 9 of appendix A-4 of this part according to the requirements in paragraphs (h)(1)(i) and(ii).

(i) Opacity readings shall be taken during the duration of three separate truck dump events. Each truck dump event commences when the truck bed begins to elevate and concludes when the truck bed returns to a horizontal position.

(ii) Compliance with the applicable opacity limit is determined by averaging all 15-second opacity readings made during the duration of three separate truck dump events.

(2) Conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible.

(3) Conduct a performance test using Method 9 of appendix A-4 of this part at least once every 5 calendar years for each affected facility.

§ 60.256 Continuous monitoring requirements.

(a) The owner or operator of each affected facility constructed, reconstructed, or modified on or before April 28, 2008, must meet the monitoring requirements specified in paragraphs (a)(1) and (2) of this section, as applicable to the affected facility.

(1) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(i) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within ±1.7 °C (±3 °F).

(ii) For affected facilities that use wet scrubber emission control equipment:

(A) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(B) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator shall have discretion to grant requests for approval of alternative monitoring locations.

(2) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under § 60.13(b).

(b) The owner or operator of each affected facility constructed, reconstructed, or modified after April 28, 2008, that has one or more mechanical vents must install, calibrate, maintain, and continuously operate the monitoring devices specified in paragraphs (b)(1) through (3) of this section, as applicable to the mechanical vent and any control device installed on the vent.

(1) For mechanical vents with fabric filters (baghouses) with design controlled potential PM emissions rates of 25 Mg (28 tons) per year or more, a bag leak detection system according to the requirements in paragraph (c) of this section.

(2) For mechanical vents with wet scrubbers, monitoring devices according to the requirements in paragraphs (b)(2)(i) through (iv) of this section.

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(ii) A monitoring device for the continuous measurement of the water supply flow rate to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply flow rate.

(iii) A monitoring device for the continuous measurement of the pH of the wet scrubber liquid. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design pH.

(iv) An average value for each monitoring parameter must be determined during each performance test. Each monitoring parameter must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis.

(3) For mechanical vents with control equipment other than wet scrubbers, a monitoring device for the continuous measurement of the reagent injection flow rate to the control equipment, as applicable. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design injection flow rate. An average reagent injection flow rate value must be determined during each performance test. The reagent injection flow rate must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis.

(c) Each bag leak detection system used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (c)(1) through (3) of this section.

(1) The bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per dry standard cubic meter (mg/dscm) (0.00044 grains per actual cubic foot (gr/acf)) or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (*e.g.,* using a strip chart recorder or a data logger).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, the owner or operator must not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(2)(vi) of this section.

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section.

(vii) The owner or operator must install the bag leak detection sensor downstream of the fabric filter.

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

(2) The owner or operator must develop and submit to the Administrator or delegated authority for approval a site-specific monitoring plan for each bag leak detection system. This plan must be submitted to the Administrator or delegated authority 30 days prior to startup of the affected facility. The owner or operator must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (c)(2)(i) through (vi) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored; and

(vi) Corrective action procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow the owner and operator more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

(3) For each bag leak detection system, the owner or operator must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

(i) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in PM emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective fabric filter compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the PM emissions.

§ 60.257 Test methods and procedures.

(a) The owner or operator must determine compliance with the applicable opacity standards as specified in paragraphs (a)(1) through (3) of this section.

(1) Method 9 of appendix A-4 of this part and the procedures in § 60.11 must be used to determine opacity, with the exceptions specified in paragraphs (a)(1)(i) and (ii).

(i) The duration of the Method 9 of appendix A-4 of this part performance test shall be 1 hour (ten 6-minute averages).

(ii) If, during the initial 30 minutes of the observation of a Method 9 of appendix A-4 of this part performance test, all of the 6-minute average opacity readings are less than or equal to half the applicable opacity limit, then the observation period may be reduced from 1 hour to 30 minutes.

(2) To determine opacity for fugitive coal dust emissions sources, the additional requirements specified in paragraphs (a)(2)(i) through (iii) must be used.

(i) The minimum distance between the observer and the emission source shall be 5.0 meters (16 feet), and the sun shall be oriented in the 140-degree sector of the back.

(ii) The observer shall select a position that minimizes interference from other fugitive coal dust emissions sources and make observations such that the line of vision is approximately perpendicular to the plume and wind direction.

(iii) The observer shall make opacity observations at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Water vapor is not considered a visible emission.

(3) A visible emissions observer may conduct visible emission observations for up to three fugitive, stack, or vent emission points within a 15-second interval if the following conditions specified in paragraphs (a)(3)(i) through (iii) of this section are met.

(i) No more than three emissions points may be read concurrently.

(ii) All three emissions points must be within a 70 degree viewing sector or angle in front of the observer such that the proper sun position can be maintained for all three points.

(iii) If an opacity reading for any one of the three emissions points is within 5 percent opacity from the applicable standard (excluding readings of zero opacity), then the observer must stop taking readings for the other two points and continue reading just that single point.

(b) The owner or operator must conduct all performance tests required by § 60.8 to demonstrate compliance with the applicable emissions standards specified in § 60.252 according to the requirements in § 60.8 using the applicable test methods and procedures in paragraphs (b)(1) through (8) of this section.

(1) Method 1 or 1A of appendix A-4 of this part shall be used to select sampling port locations and the number of traverse points in each stack or duct. Sampling sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.

(2) Method 2, 2A, 2C, 2D, 2F, or 2G of appendix A-4 of this part shall be used to determine the volumetric flow rate of the stack gas.

(3) Method 3, 3A, or 3B of appendix A-4 of this part shall be used to determine the dry molecular weight of the stack gas. The owner or operator may use ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses (incorporated by reference— *see* § 60.17) as an alternative to Method 3B of appendix A-2 of this part.

(4) Method 4 of appendix A-4 of this part shall be used to determine the moisture content of the stack gas.

(5) Method 5, 5B or 5D of appendix A-4 of this part or Method 17 of appendix A-7 of this part shall be used to determine the PM concentration as follows:

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test.

(ii) Method 5 of appendix A of this part shall be used only to test emissions from affected facilities without wet flue gas desulfurization (FGD) systems.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(iv) Method 5D of appendix A-4 of this part shall be used for positive pressure fabric filters and other similar applications (*e.g.,* stub stacks and roof vents).

(v) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 ° C (320 ° F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(6) Method 6, 6A, or 6C of appendix A-4 of this part shall be used to determine the SO_2 concentration. A minimum of three valid test runs are needed to comprise an SO_2 performance test.

(7) Method 7 or 7E of appendix A-4 of this part shall be used to determine the NO_X concentration. A minimum of three valid test runs are needed to comprise an NO_X performance test.

(8) Method 10 of appendix A-4 of this part shall be used to determine the CO concentration. A minimum of three valid test runs are needed to comprise a CO performance test. CO performance tests are conducted concurrently (or within a 60-minute period) with NO_X performance tests.

§ 60.258 Reporting and recordkeeping.

(a) The owner or operator of a coal preparation and processing plant that commenced construction, reconstruction, or modification after April 28, 2008, shall maintain in a logbook (written or electronic) on-site and make it available upon request. The logbook shall record the following:

(1) The manufacturer's recommended maintenance procedures and the date and time of any maintenance and inspection activities and the results of those activities. Any variance from manufacturer recommendation, if any, shall be noted.

(2) The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions shall be noted.

(3) The amount and type of coal processed each calendar month.

(4) The amount of chemical stabilizer or water purchased for use in the coal preparation and processing plant.

(5) Monthly certification that the dust suppressant systems were operational when any coal was processed and that manufacturer's recommendations were followed for all control systems. Any variance from the manufacturer's recommendations, if any, shall be noted.

(6) Monthly certification that the fugitive coal dust emissions control plan was implemented as described. Any variance from the plan, if any, shall be noted. A copy of the applicable fugitive coal dust emissions control plan and any letters from the Administrator providing approval of any alternative control measures shall be maintained with the logbook. Any actions, *e.g.* objections, to the plan and any actions relative to the alternative control measures, *e.g.* approvals, shall be noted in the logbook as well.

(7) For each bag leak detection system, the owner or operator must keep the records specified in paragraphs (a)(7)(i) through (iii) of this section.

(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the cause of the alarm was alleviated within 3 hours of the alarm.

(8) A copy of any applicable monitoring plan for a digital opacity compliance system and monthly certification that the plan was implemented as described. Any variance from plan, if any, shall be noted.

(9) During a performance test of a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the scrubber pressure loss, water supply flow rate, and pH of the wet scrubber liquid.

(10) During a performance test of control equipment other than a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the reagent injection flow rate, as applicable.

(b) For the purpose of reports required under section 60.7(c), any owner operator subject to the provisions of this subpart also shall report semiannually periods of excess emissions as follow:

(1) The owner or operator of an affected facility with a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the scrubber pressure loss, water supply flow rate, or pH of the wet scrubber liquid vary by more than 10 percent from the average determined during the most recent performance test.

(2) The owner or operator of an affected facility with control equipment other than a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the reagent injection flow rate, as applicable, vary by more than 10 percent from the average determined during the most recent performance test.

(3) All 6-minute average opacities that exceed the applicable standard.

(c) The owner or operator of an affected facility shall submit the results of initial performance tests to the Administrator or delegated authority, consistent with the provisions of section 60.8. The owner or operator who elects to comply with the reduced performance testing provisions of sections 60.255(c) or (d) shall include in the performance test report identification of each affected facility that will be subject to the reduced testing. The owner or operator electing to comply with section 60.255(d) shall also include information which demonstrates that the control devices are identical.

(d) After July 1, 2011, within 60 days after the date of completing each performance evaluation conducted to demonstrate compliance with this subpart, the owner or operator of the affected facility must submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.* For performance tests that cannot be entered into WebFIRE (*i.e.,* Method 9 of appendix A-4 of this part opacity performance tests) the owner or operator of the affected facility must mail a summary copy to United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; mail code: D243-01; RTP, NC 27711.

Attachment G

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on May 20, 2013]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart GGGa—Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

Source: 72 FR 64896, Nov. 16, 2007, unless otherwise noted.

§ 60.590a Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in petroleum refineries.

(2) A compressor is an affected facility.

(3) The group of all the equipment (defined in § 60.591a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, is subject to the requirements of this subpart.

(c) Addition or replacement of equipment (defined in § 60.591a) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d) Facilities subject to subpart VV, subpart VVa, subpart GGG, or subpart KKK of this part are excluded from this subpart.

(e) *Stay of standards.* Owners or operators are not required to comply with the definition of “process unit” in § 60.590 of this subpart until the EPA takes final action to require compliance and publishes a document in the FEDERAL REGISTER. While the definition of “process unit” is stayed, owners or operators should use the following definition:

Process unit means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

[49 FR 22606, May 30, 1984, as amended at 73 FR 31376, June 2, 2008]

§ 60.591a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act, in subpart A of part 60, or in subpart VVa of this part, and the following terms shall have the specific meanings given them.

Alaskan North Slope means the approximately 69,000 square mile area extending from the Brooks Range to the Arctic Ocean.

Asphalt (also known as Bitumen) is a black or dark brown solid or semi-solid thermo-plastic material possessing waterproofing and adhesive properties. It is a complex combination of higher molecular weight organic compounds containing a relatively high proportion of hydrocarbons having carbon numbers greater than C25 with a high carbon to hydrogen ratio. It is essentially non-volatile at ambient temperatures with closed cup flash point of 445 °F (230 °C) or greater.

Equipment means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment.

In hydrogen service means that a compressor contains a process fluid that meets the conditions specified in § 60.593a(b).

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.593a(c).

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

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

Process unit means the components assembled and connected by pipes or ducts to process raw materials and to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in § 60.482-1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

EFFECTIVE DATE NOTE: At 73 FR 31376, June 2, 2008, § 60.591a, the definition of “process unit” was stayed until further notice.

§ 60.592a Standards.

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

(b) For a given process unit, an owner or operator may elect to comply with the requirements of paragraphs (b)(1), (2), or (3) of this section as an alternative to the requirements in § 60.482-7a.

(1) Comply with § 60.483-1a.

(2) Comply with § 60.483-2a.

(3) Comply with the Phase III provisions in § 63.168, except an owner or operator may elect to follow the provisions in § 60.482-7a(f) instead of § 63.168 for any valve that is designated as being leakless.

(c) An owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of § 60.484a.

(d) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of § 60.485a except as provided in § 60.593a.

(e) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §§ 60.486a and 60.487a.

§ 60.593a Exceptions.

(a) Each owner or operator subject to the provisions of this subpart may comply with the following exceptions to the provisions of subpart VVa of this part.

(b)(1) Compressors in hydrogen service are exempt from the requirements of § 60.592a if an owner or operator demonstrates that a compressor is in hydrogen service.

(2) Each compressor is presumed not to be in hydrogen service unless an owner or operator 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 E260-73, 91, or 96, E168-67, 77, or 92, or E169-63, 77, or 93 (incorporated by reference as specified in § 60.17) shall be used.

(3)(i) An owner or operator 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 an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in paragraph (b)(2) of this section shall be used to resolve the disagreement.

(ii) If an owner or operator 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 § 60.14 or § 60.15 is exempt from § 60.482-3a(a), (b), (c), (d), (e), and (h) provided the owner or operator 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 § 60.482-3a(a), (b), (c), (d), (e), and (h).

(d) An owner or operator may use the following provision in addition to § 60.485a(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C as determined by ASTM Method D86-78, 82, 90, 93, 95, or 96 (incorporated by reference as specified in § 60.17).

(e) Pumps in light liquid service and valves in gas/vapor and light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the requirements of §§ 60.482-2a and 60.482-7a.

(f) Open-ended valves or lines containing asphalt as defined in § 60.591a are exempt from the requirements of § 60.482-6a(a) through (c).

(g) Connectors in gas/vapor or light liquid service are exempt from the requirements in § 60.482-11a, provided the owner or operator complies with § 60.482-8a for all connectors, not just those in heavy liquid service.

Attachment H

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on July 19, 2016]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart NNN—Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations

Source: 55 FR 26942, June 29, 1990, unless otherwise noted.

§60.660 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to each affected facility designated in paragraph (b) of this section that is part of a process unit that produces any of the chemicals listed in §60.667 as a product, co-product, by-product, or intermediate, except as provided in paragraph (c).

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after December 30, 1983:

(1) Each distillation unit not discharging its vent stream into a recovery system.

(2) Each combination of a distillation unit and the recovery system into which its vent stream is discharged.

(3) Each combination of two or more distillation units and the common recovery system into which their vent streams are discharged.

(c) Exemptions from the provisions of paragraph (a) of this section are as follows:

(1) Any distillation unit operating as part of a process unit which produces coal tar or beverage alcohols, or which uses, contains, and produces no VOC is not an affected facility.

(2) Any distillation unit that is subject to the provisions of subpart DDD is not an affected facility.

(3) Any distillation unit that is designed and operated as a batch operation is not an affected facility.

(4) Each affected facility that has a total resource effectiveness (TRE) index value greater than 8.0 is exempt from all provisions of this subpart except for §§60.662; 60.664 (e), (f), and (g); and 60.665 (h) and (l).

(5) Each affected facility in a process unit with a total design capacity for all chemicals produced within that unit of less than one gigagram per year is exempt from all provisions of this subpart except for the recordkeeping and reporting requirements in paragraphs (j), (l)(6), and (n) of §60.665.

(6) Each affected facility operated with a vent stream flow rate less than 0.008 scm/min is exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in §60.664(g) and paragraphs (i), (l)(5), and (o) of §60.665.

(d) *Alternative means of compliance*—(1) *Option to comply with part 65.* Owners or operators of process vents that are subject to this subpart may choose to comply with the provisions of 40 CFR part 65, subpart D, to satisfy the requirements of §§60.662 through 60.665 and 60.668. The provisions of 40 CFR part 65 also satisfy the criteria of paragraphs (c)(4) and (6) of this section. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart D, 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 process vents. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (d)(2) do not apply to owners or operators of process vents complying with 40 CFR part 65, subpart D, 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 D, must comply with 40 CFR part 65, subpart A.

(3) *Compliance date.* Owners or operators who choose to comply with 40 CFR part 65, subpart D, at initial startup shall comply with paragraphs (d)(1) and (2) of this section for each vent stream on and after the date on which the initial performance test 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 the initial startup, whichever date comes first.

(4) *Initial startup notification.* Each owner or operator subject to the provisions of this subpart that chooses to comply with 40 CFR part 65, subpart D, at initial startup shall notify the Administrator of the specific provisions of 40 CFR 65.63(a)(1), (2), or (3), with which the owner or operator has elected to comply. Notification shall be submitted with the notifications of initial startup required by 40 CFR 65.5(b).

[NOTE: The intent of these standards is to minimize the emissions of VOC through the application of best demonstrated technology (BDT). The numerical emission limits in these standards are expressed in terms of total organic compounds (TOC), measured as TOC less methane and ethane. This emission limit reflects the performance of BDT.]

[55 FR 26942, June 29, 2000, as amended at 65 FR 78279, Dec. 14, 2000; 79 FR 11251, Feb. 27, 2014]

§60.661 Definitions.

As used in this subpart, all terms not defined here shall have the meaning given them in the Act and in subpart A of part 60, and the following terms shall have the specific meanings given them.

Batch distillation operation means a noncontinuous distillation operation in which a discrete quantity or batch of liquid feed is charged into a distillation unit and distilled at one time. After the initial charging of the liquid feed, no additional liquid is added during the distillation operation.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam.

By compound means by individual stream components, not carbon equivalents.

Continuous recorder means a data recording device recording an instantaneous data value at least once every 15 minutes.

Distillation operation means an operation separating one or more feed stream(s) into two or more exit stream(s), each exit stream having component concentrations different from those in the feed stream(s). The separation is achieved by the redistribution of the components between the liquid and vapor-phase as they approach equilibrium within the distillation unit.

Distillation unit means a device or vessel in which distillation operations occur, including all associated internals (such as trays or packing) and accessories (such as reboiler, condenser, vacuum pump, steam jet, etc.), plus any associated recovery system.

Flame zone means the portion of the combustion chamber in a boiler occupied by the flame envelope.

Flow indicator means a device which indicates whether gas flow is present in a vent stream.

Halogenated vent stream means any vent stream determined to have a total concentration (by volume) of compounds containing halogens of 20 ppmv (by compound) or greater.

Incinerator means any enclosed combustion device that is used for destroying organic compounds and does not extract energy in the form of steam or process heat.

Process heater means a device that transfers heat liberated by burning fuel to fluids contained in tubes, including all fluids except water that is heated to produce steam.

Process unit means equipment assembled and connected by pipes or ducts to produce, as intermediates or final products, one or more of the chemicals in §60.667. A process unit can operate independently if supplied with sufficient fuel or raw materials and sufficient product storage facilities.

Product means any compound or chemical listed in §60.667 that is produced for sale as a final product as that chemical, or for use in the production of other chemicals or compounds. By-products, co-products, and intermediates are considered to be products.

Recovery device means an individual unit of equipment, such as an absorber, carbon adsorber, or condenser, capable of and used for the purpose of recovering chemicals for use, reuse, or sale.

Recovery system means an individual recovery device or series of such devices applied to the same vent stream.

Total organic compounds (TOC) means those compounds measured according to the procedures in §60.664(b)(4). For the purposes of measuring molar composition as required in §60.664(d)(2)(i); hourly emissions rate as required in §60.664(d)(5) and §60.664(e); and TOC concentration as required in §60.665(b)(4) and §60.665(g)(4), those compounds which the Administrator has determined do not contribute appreciably to the formation of ozone are to be excluded. The compounds to be excluded are identified in Environmental Protection Agency's statements on ozone abatement policy for State Implementation Plans (SIP) revisions (42 FR 35314; 44 FR 32042; 45 FR 32424; 45 FR 48942).

TRE index value means a measure of the supplemental total resource requirement per unit reduction of TOC associated with an individual distillation vent stream, based on vent stream flow rate, emission rate of TOC net heating value, and corrosion properties (whether or not the vent stream is halogenated), as quantified by the equation given under §60.664(e).

Vent stream means any gas stream discharged directly from a distillation facility to the atmosphere or indirectly to the atmosphere after diversion through other process equipment. The vent stream excludes relief valve discharges and equipment leaks including, but not limited to, pumps, compressors, and valves.

§60.662 Standards.

Each owner or operator of any affected facility shall comply with paragraph (a), (b), or (c) of this section for each vent stream on and after the date on which the initial performance test required by §60.8 and §60.664 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 the initial start-up, whichever date comes first. Each owner or operator shall either:

(a) Reduce emissions of TOC (less methane and ethane) by 98 weight-percent, or to a TOC (less methane and ethane) concentration of 20 ppmv, on a dry basis corrected to 3 percent oxygen, whichever is less stringent. If a boiler or process heater is used to comply with this paragraph, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or

(b) Combust the emissions in a flare that meets the requirements of §60.18; or

(c) Maintain a TRE index value greater than 1.0 without use of VOC emission control devices.

§60.663 Monitoring of emissions and operations.

(a) The owner or operator of an affected facility that uses an incinerator to seek to comply with the TOC emission limit specified under §60.662(a) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment:

(1) A temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater.

(i) Where an incinerator other than a catalytic incinerator is used, a temperature monitoring device shall be installed in the firebox.

(ii) Where a catalytic incinerator is used, temperature monitoring devices shall be installed in the gas stream immediately before and after the catalyst bed.

(2) A flow indicator that provides a record of vent stream flow to the incinerator at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each affected facility at a point closest to the inlet of each incinerator and before being joined with any other vent stream.

(b) The owner or operator of an affected facility that uses a flare to seek to comply with §60.662(b) shall install, calibrate, maintain and operate according to manufacturer's specifications the following equipment:

(1) A heat sensing device, such as an ultra-violet beam sensor or thermocouple, at the pilot light to indicate the continuous presence of a flame.

(2) A flow indicator that provides a record of vent stream flow to the flare at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each affected facility at a point closest to the flare and before being joined with any other vent stream.

(c) The owner or operator of an affected facility that uses a boiler or process heater to seek to comply with §60.662(a) shall install, calibrate, maintain and operate according to the manufacturer's specifications the following equipment:

(1) A flow indicator that provides a record of vent stream flow to the boiler or process heater at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each distillation unit within an affected facility at a point closest to the inlet of each boiler or process heater and before being joined with any other vent stream.

(2) A temperature monitoring device in the firebox equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being measured expressed in degrees Celsius or ±0.5 °C, whichever is greater, for boilers or process heaters of less than 44 MW (150 million Btu/hr) heat input design capacity.

(d) Monitor and record the periods of operation of the boiler or process heater if the design heat input capacity of the boiler or process heater is 44 MW (150 million Btu/hr) or greater. The records must be readily available for inspection.

(e) The owner or operator of an affected facility that seeks to comply with the TRE index value limit specified under §60.662(c) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator:

(1) Where an absorber is the final recovery device in the recovery system:

(i) A scrubbing liquid temperature monitoring device having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater, and a specific gravity monitoring device having an accuracy of ±0.02 specific gravity units, each equipped with a continuous recorder, or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infrared, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(2) Where a condenser is the final recovery device in the recovery system:

(i) A condenser exit (product side) temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater, or

(ii) An organic monitoring device used to monitor organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(3) Where a carbon adsorber is the final recovery device unit in the recovery system:

(i) An integrating steam flow monitoring device having an accuracy of ±10 percent, and a carbon bed temperature monitoring device having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater, both equipped with a continuous recorder, or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(f) An owner or operator of an affected facility seeking to demonstrate compliance with the standards specified under §60.662 with control devices other than incinerator, boiler, process heater, or flare; or recovery device other than an absorber, condenser, or carbon adsorber shall provide to the Administrator information describing the operation of the control device or recovery device and the process parameter(s) which would indicate proper operation and maintenance of the device. The Administrator may request further information and will specify appropriate monitoring procedures or requirements.

[55 FR 26942, June 29, 1990, as amended at 65 FR 61774, Oct. 17, 2000]

§60.664 Test methods and procedures.

(a) For the purpose of demonstrating compliance with §60.662, all affected facilities shall be run at full operating conditions and flow rates during any performance test.

(b) The following methods in appendix A to this part, except as provided under §60.8(b), shall be used as reference methods to determine compliance with the emission limit or percent reduction efficiency specified under §60.662(a).

(1) Method 1 or 1A, as appropriate, for selection of the sampling sites. The control device inlet sampling site for determination of vent stream molar composition or TOC (less methane and ethane) reduction efficiency shall be prior to the inlet of the control device and after the recovery system.

(2) Method 2, 2A, 2C, or 2D, as appropriate, for determination of the gas volumetric flow rates.

(3) The emission rate correction factor, integrated sampling and analysis procedure of Method 3 shall be used to determine the oxygen concentration ($\%O_{2d}$) for the purposes of determining compliance with the 20 ppmv limit. The sampling site shall be the same as that of the TOC samples, and the samples shall be taken during the same time that the TOC samples are taken.

The TOC concentration corrected to 3 percent 0_2 (C_c) shall be computed using the following equation:

$$C_c = C_{TOC}\frac{17.9}{20.9 - \%O_{2d}}$$

where:

C_c = Concentration of TOC corrected to 3 percent O_2, dry basis, ppm by volume.

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

$\%O_{2d}$ = Concentration of O_2, dry basis, percent by volume.

(4) Method 18 to determine the concentration of TOC in the control device outlet and the concentration of TOC in the inlet when the reduction efficiency of the control device is to be determined.

(i) The sampling time for each run shall be 1 hour in which either an integrated sample or four grab samples shall be taken. If grab sampling is used then the samples shall be taken at 15-minute intervals.

(ii) The emission reduction (R) of TOC (minus methane and ethane) shall be determined using the following equation:

$$R = \frac{E_i - E_o}{E_i} \times 100$$

where:

R = Emission reduction, percent by weight.

E_i = Mass rate of TOC entering the control device, kg/hr (lb/hr).

E_o = Mass rate of TOC discharged to the atmosphere, kg/hr (lb/hr).

(iii) The mass rates of TOC (E_i, E_o) shall be computed using the following equations:

$$E_i = K_2\left(\sum_{j=1}^{n} C_{ij}M_{ij}\right)Q_i$$

$$E_O = K_2\left(\sum_{j=1}^{n} C_{oj}M_{oj}\right)Q_O$$

where:

C_{ij}, C_{oj} = Concentration of sample component “j” of the gas stream at the inlet and outlet of the control device, respectively, dry basis, ppm by volume.

M_{ij}, M_{oj} = Molecular weight of sample component “j” of the gas stream at the inlet and outlet of the control device, respectively, g/g-mole (lb/lb-mole).

Q_i, Q_o = Flow rate of gas stream at the inlet and outlet of the control device, respectively, dscm/min (dscf/min).

$K_2 = 2.494 \times 10^{-6}$ (1/ppm)(g-mole/scm) (kg/g) (min/hr) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.557 × 10^{-7} (1/ppm) (lb-mole/scf) (min/hr) (English units), where standard temperature for (lb-mole/scf) is 68 °F.

(iv) The TOC concentration (C_{TOC}) is the sum of the individual components and shall be computed for each run using the following equation:

$$C_{TOC} = \sum_{j=1}^{n} C_j$$

where:

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

C_j = Concentration of sample components "j", dry basis, ppm by volume.

n = Number of components in the sample.

(c) When a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to seek to comply with §60.662(a), the requirement for an initial performance test is waived, in accordance with §60.8(b). However, the Administrator reserves the option to require testing at such other times as may be required, as provided for in section 114 of the Act.

(d) When a flare is used to seek to comply with §60.662(b), the flare shall comply with the requirements of §60.18.

(e) The following test methods in appendix A to this part, except as provided under §60.8(b), shall be used for determining the net heating value of the gas combusted to determine compliance under §60.662(b) and for determining the process vent stream TRE index value to determine compliance under §60.662(c).

(1)(i) Method 1 or 1A, as appropriate, for selection of the sampling site. The sampling site for the vent stream flow rate and molar composition determination prescribed in §60.664(e)(2) and (3) shall be, except for the situations outlined in paragraph (e)(1)(ii) of this section, prior to the inlet of any control device, prior to any post-distillation dilution of the stream with air, and prior to any post-distillation introduction of halogenated compounds into the process vent stream. No transverse site selection method is needed for vents smaller than 10 centimeters (4 inches) in diameter.

(ii) If any gas stream other than the distillation vent stream from the affected facility is normally conducted through the final recovery device.

(A) The sampling site for vent stream flow rate and molar composition shall be prior to the final recovery device and prior to the point at which the nondistillation stream is introduced.

(B) The efficiency of the final recovery device is determined by measuring the TOC concentration using Method 18 at the inlet to the final recovery device after the introduction of any nondistillation vent stream and at the outlet of the final recovery device.

(C) This efficiency is applied to the TOC concentration measured prior to the final recovery device and prior to the introduction of the nondistillation stream to determine the concentration of TOC in the distillation vent stream from the final recovery device. This concentration of TOC is then used to perform the calculations outlined in §60.664(e)(4) and (5).

(2) The molar composition of the process vent stream shall be determined as follows:

(i) Method 18 to measure the concentration of TOC including those containing halogens.

(ii) ASTM D1946-77 or 90 (Reapproved 1994) (incorporation by reference as specified in §60.17 of this part) to measure the concentration of carbon monoxide and hydrogen.

(iii) Method 4 to measure the content of water vapor.

(3) The volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D, as appropriate.

(4) The net heating value of the vent stream shall be calculated using the following equation:

$$H_T = K_1\left(\sum_{j=1}^{n} C_j H_j\right)$$

where:

H_T = Net heating value of the sample, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (77 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F).

K_1 = 1.74×10^{-7} (1/ppm) (g-mole/scm) (MJ/kcal) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.03×10^{-11} (1/ppm) (lb-mole/scf) (Btu/kcal) (English units) where standard temperature for (lb/mole/scf) is 68 °F.

C_j = Concentration on a wet basis of compound j in ppm, as measured for organics by Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (incorporation by reference as specified in §60.17 of this part) as indicated in §60.664(e)(2).

H_j = Net heat of combustion of compound j, kcal/(g-mole) [kcal/(lb-mole)], based on combustion at 25 °C and 760 mm Hg (77 °F and 30 in. Hg).

The heats of combustion of vent stream components would be required to be determined using ASTM D2382-76 (incorporation by reference as specified in §60.17 of this part) if published values are not available or cannot be calculated.

(5) The emission rate of TOC in the vent stream shall be calculated using the following equation:

$$E_{TOC} = K_2\left[\sum_{j=1}^{n} C_j M_j\right] Q_s$$

where:

E_{TOC} = Measured emission rate of TOC, kg/hr (lb/hr).

K_2 = 2.494×10^{-6} (1/ppm) (g-mole/scm) (kg/g) (min/hr) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.557×10^{-7} (1/ppm) (lb-mole/scf) (min/hr) (English units), where standard temperature for (lb-mole/scf) is 68 °F.

C_j = Concentration on a wet basis of compound j in ppm, as measured by Method 18 as indicated in §60.664(e)(2).

M_j = Molecular weight of sample j, g/g-mole (lb/lb-mole).

Q_s = Vent stream flow rate, scm/min (scf/min), at a temperature of 20 °C (68 °F).

(6) The total process vent stream concentration (by volume) of compounds containing halogens (ppmv, by compound) shall be summed from the individual concentrations of compounds containing halogens which were measured by Method 18.

(f) For purposes of complying with §60.662(c) the owner or operator of a facility affected by this subpart shall calculate the TRE index value of the vent stream using the equation for incineration in paragraph (e)(1) of this section for halogenated vent streams. The owner or operator of an affected facility with a nonhalogenated vent stream shall determine the TRE index value by calculating values using both the incinerator equation in (e)(1) and the flare equation in (e)(2) of this section and selecting the lower of the two values.

(1) The equation for calculating the TRE index value of a vent stream controlled by an incinerator is as follows:

$$TRE=\frac{1}{E_{TOC}}\left[a+b\left(Q_s\right)+c\left(Q_s\right)^{0.88}+d\left(Q_s\right)\left(H_T\right)+e\left(Q_s\right)^{0.88}\left(H_T\right)^{0.88}+f\left(Y_s\right)^{0.5}\right]$$

(i) Where for a vent stream flow rate that is greater than or equal to 14.2 scm/min (501 scf/min) at a standard temperature of 20 °C (68 °F):

TRE = TRE index value.

Q_s = Vent stream flow rate, scm/min (scf/min), at a temperature of 20 °C (68 °F).

H_T = Vent stream net heating value, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (68 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F) as in the definition of Q_s.

Y_s = Q_s for all vent stream categories listed in table 1 except for Category E vent streams where $Y_s = Q_sH_T/3.6$.

E_{TOC} = Hourly emissions of TOC, kg/hr (lb/hr).

a, b, c, d, e, and f are coefficients.

The set of coefficients that apply to a vent stream can be obtained from table 1.

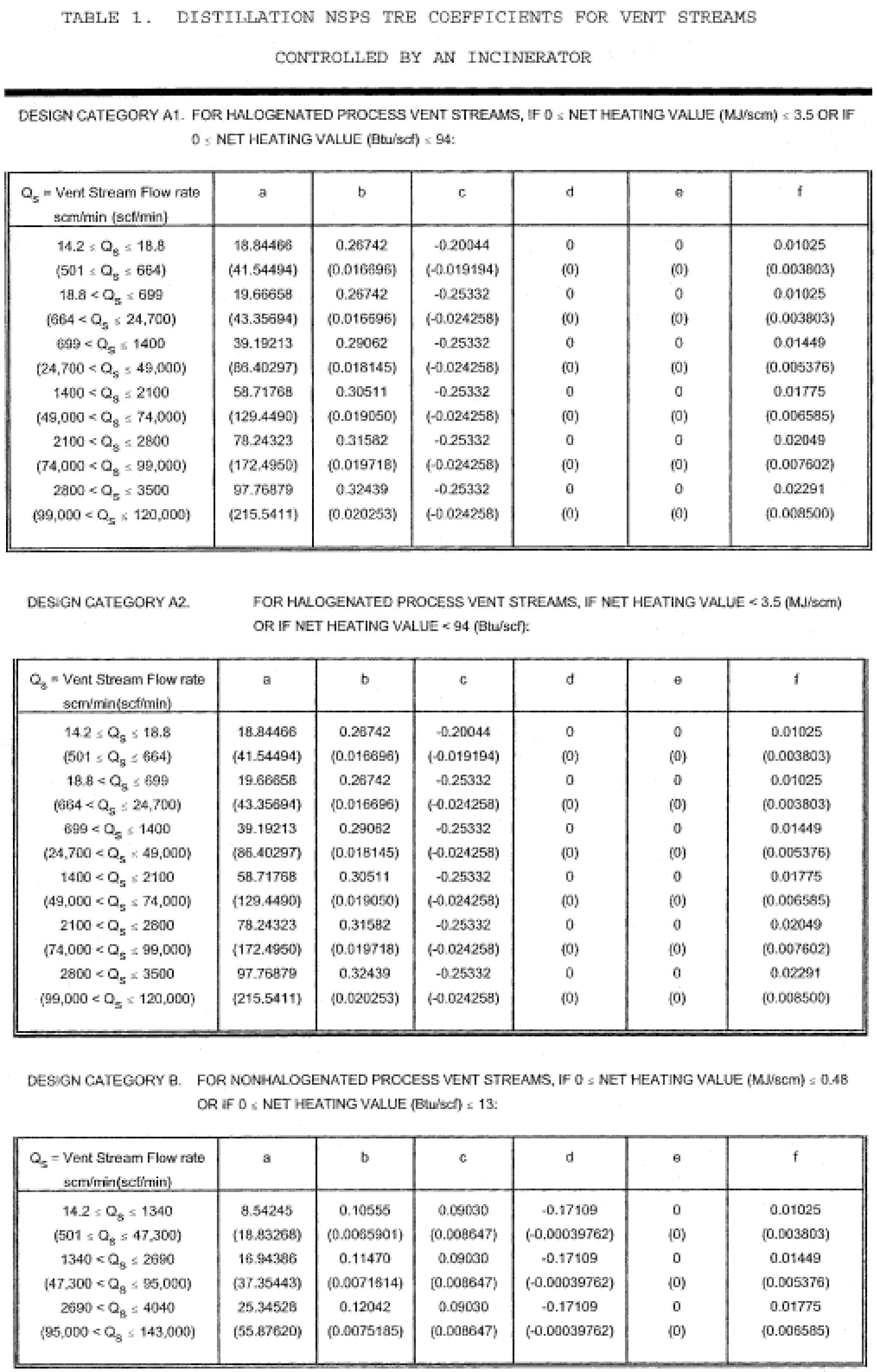

TABLE 1. DISTILLATION NSPS TRE COEFFICIENTS FOR VENT STREAMS CONTROLLED BY AN INCINERATOR

DESIGN CATEGORY A1. FOR HALOGENATED PROCESS VENT STREAMS, IF $0 \le$ NET HEATING VALUE (MJ/scm) ≤ 3.5 OR IF $0 \le$ NET HEATING VALUE (Btu/scf) ≤ 94:

Q_s = Vent Stream Flow rate scm/min (scf/min)	a	b	c	d	e	f
$14.2 \le Q_s \le 18.8$	18.84466	0.26742	-0.20044	0	0	0.01025
$(501 \le Q_s \le 664)$	(41.54494)	(0.016696)	(-0.019194)	(0)	(0)	(0.003803)
$18.8 < Q_s \le 699$	19.66658	0.26742	-0.25332	0	0	0.01025
$(664 < Q_s \le 24{,}700)$	(43.35694)	(0.016696)	(-0.024258)	(0)	(0)	(0.003803)
$699 < Q_s \le 1400$	39.19213	0.29062	-0.25332	0	0	0.01449
$(24{,}700 < Q_s \le 49{,}000)$	(86.40297)	(0.018145)	(-0.024258)	(0)	(0)	(0.005376)
$1400 < Q_s \le 2100$	58.71768	0.30511	-0.25332	0	0	0.01775
$(49{,}000 < Q_s \le 74{,}000)$	(129.4490)	(0.019050)	(-0.024258)	(0)	(0)	(0.006585)
$2100 < Q_s \le 2800$	78.24323	0.31582	-0.25332	0	0	0.02049
$(74{,}000 < Q_s \le 99{,}000)$	(172.4950)	(0.019718)	(-0.024258)	(0)	(0)	(0.007602)
$2800 < Q_s \le 3500$	97.76879	0.32439	-0.25332	0	0	0.02291
$(99{,}000 < Q_s \le 120{,}000)$	(215.5411)	(0.020253)	(-0.024258)	(0)	(0)	(0.008500)

DESIGN CATEGORY A2. FOR HALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE < 3.5 (MJ/scm) OR IF NET HEATING VALUE < 94 (Btu/scf):

Q_s = Vent Stream Flow rate scm/min(scf/min)	a	b	c	d	e	f
$14.2 \le Q_s \le 18.8$	18.84466	0.26742	-0.20044	0	0	0.01025
$(501 \le Q_s \le 664)$	(41.54494)	(0.016696)	(-0.019194)	(0)	(0)	(0.003803)
$18.8 < Q_s \le 699$	19.66658	0.26742	-0.25332	0	0	0.01025
$(664 < Q_s \le 24{,}700)$	(43.35694)	(0.016696)	(-0.024258)	(0)	(0)	(0.003803)
$699 < Q_s \le 1400$	39.19213	0.29062	-0.25332	0	0	0.01449
$(24{,}700 < Q_s \le 49{,}000)$	(86.40297)	(0.018145)	(-0.024258)	(0)	(0)	(0.005376)
$1400 < Q_s \le 2100$	58.71768	0.30511	-0.25332	0	0	0.01775
$(49{,}000 < Q_s \le 74{,}000)$	(129.4490)	(0.019050)	(-0.024258)	(0)	(0)	(0.006585)
$2100 < Q_s \le 2800$	78.24323	0.31582	-0.25332	0	0	0.02049
$(74{,}000 < Q_s \le 99{,}000)$	(172.4950)	(0.019718)	(-0.024258)	(0)	(0)	(0.007602)
$2800 < Q_s \le 3500$	97.76879	0.32439	-0.25332	0	0	0.02291
$(99{,}000 < Q_s \le 120{,}000)$	(215.5411)	(0.020253)	(-0.024258)	(0)	(0)	(0.008500)

DESIGN CATEGORY B. FOR NONHALOGENATED PROCESS VENT STREAMS, IF $0 \le$ NET HEATING VALUE (MJ/scm) ≤ 0.48 OR IF $0 \le$ NET HEATING VALUE (Btu/scf) ≤ 13:

Q_s = Vent Stream Flow rate scm/min(scf/min)	a	b	c	d	e	f
$14.2 \le Q_s \le 1340$	8.54245	0.10555	0.09030	-0.17109	0	0.01025
$(501 \le Q_s \le 47{,}300)$	(18.83268)	(0.0065901)	(0.008647)	(-0.00039762)	(0)	(0.003803)
$1340 < Q_s \le 2690$	16.94386	0.11470	0.09030	-0.17109	0	0.01449
$(47{,}300 < Q_s \le 95{,}000)$	(37.35443)	(0.0071614)	(0.008647)	(-0.00039762)	(0)	(0.005376)
$2690 < Q_s \le 4040$	25.34528	0.12042	0.09030	-0.17109	0	0.01775
$(95{,}000 < Q_s \le 143{,}000)$	(55.87620)	(0.0075185)	(0.008647)	(-0.00039762)	(0)	(0.006585)

DESIGN CATEGORY C. FOR NONHALOGENTED PROCESS VENT STREAMS, IF 0.48 < NET HEATING VALUE (MJ/scm) ≤ 1.9 OR IF 13 < NET HEATING VALUE (Btu/scf) ≤ 51:

Q_s = Vent Stream Flow rate scm/min(scf/min)	a	b	c	d	e	f
$14.2 \le Q_s \le 1340$	9.25233	0.06105	0.31937	-0.16181	0	0.01025
$(501 \le Q_s \le 47{,}300)$	(20.39769)	(0.003812)	(0.030582)	(-0.00037605)	(0)	(0.003803)
$1340 < Q_s \le 2690$	18.36363	0.06635	0.31937	-0.16181	0	0.01449
$(47{,}300 < Q_s \le 95{,}000)$	(40.48446)	(0.004143)	(0.030582)	(-0.00037605)	(0)	(0.005376)
$2690 < Q_s \le 4040$	27.47492	0.06965	0.31937	-0.16181	0	0.01775
$(95{,}000 < Q_s \le 143{,}000)$	(60.57121)	(0.004349)	(0.030582)	(-0.00037605)	(0)	(0.006585)

DESIGN CATEGORY D. FOR NONHALOGENATED PROCESS VENT STREAMS, IF 1.9 < NET HEATING VALUE (MJ/scm) ≤ 3.6 OR IF 51 < NET HEATING VALUE (Btu/scf) ≤ 97:

Q_s = Vent Stream Flow rate scm/min(scf/min)	a	b	c	d	e	f
$14.2 \le Q_s \le 1180$	6.67868	0.06943	0.02582	0	0	0.01025
$(501 \le Q_s \le 41{,}700)$	(14.72382)	(0.004335)	(0.002472)	(0)	(0)	(0.003803)
$1180 < Q_s \le 2370$	13.21633	0.07546	0.02582	0	0	0.01449
$(41{,}700 < Q_s \le 83{,}700)$	(29.13672)	(0.004711)	(0.002472)	(0)	(0)	(0.005376)
$2370 < Q_s \le 3550$	19.75398	0.07922	0.02582	0	0	0.01775
$(83{,}700 < Q_s \le 125{,}000)$	(43.54962)	(0.004946)	(0.002472)	(0)	(0)	(0.006585)

DESIGN CATEGORY E. FOR NONHALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE > 3.6 MJ/scm OR IF NET HEATING VALUE > 97 (Btu/scf):

Q_s = Vent Stream Flow rate scm/min(scf/min)	a	b	c	d	e	f
$14.2 \le Y_s \le 1180$	6.67868	0	0	-0.00707	0.02220	0.01025
$(501 \le Y_s \le 41{,}700)$	(14.72382)	(0)	(0)	(-0.0000164)	(0.0001174)	(0.003803)
$1180 < Y_s \le 2370$	13.21633	0	0	-0.00707	0.02412	0.01449
$(41{,}700 < Y_s \le 83{,}700)$	(29.13672)	(0)	(0)	(-0.0000164)	(0.0001276)	(0.005376)
$2370 < Y_s \le 3550$	19.75398	0	0	-0.00707	0.02533	0.01775
$(83{,}700 < Y_s \le 125{,}000)$	(43.54962)	(0)	(0)	(-0.0000164)	(0.0001340)	(0.006585)

(ii) Where for a vent stream flow rate that is less than 14.2 scm/min (501 scf/min) at a standard temperature of 20 °C (68 °F):

TRE = TRE index value.

Q_s = 14.2 scm/min (501 scf/min).

H_T = (FLOW) (HVAL)/Q_s.

Where the following inputs are used:

FLOW = Vent stream flow rate, scm/min (scf/min), at a temperature of 20 °C (68 °F).

HVAL = Vent stream net heating value, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (68 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F) as in the definition of Q_s.

$Y_s = Q_s$ for all vent stream categories listed in table 1 except for Category E vent streams where $Y_s = Q_sH_T/3.6$.

E_{TOC} = Hourly emissions of TOC, kg/hr (lb/hr).

a, b, c, d, e, and f are coefficients

The set of coefficients that apply to a vent stream can be obtained from table 1.

(2) The equation for calculating the TRE index value of a vent stream controlled by a flare is as follows:

$$TRE = \frac{1}{E_{TOC}}\left[a\left(Q_s\right)+b\left(Q_s\right)^{0.8}+c\left(Q_s\right)\left(H_T\right)+d\left(E_{TOC}\right)+e\right]$$

where:

TRE = TRE index value.

E_{TOC} = Hourly emissions of TOC, kg/hr (lb/hr).

Q_s = Vent stream flow rate, scm/min (scf/min), at a standard temperature of 20 °C (68 °F).

H_T = Vent stream net heating value, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (68 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F) as in the definition of Q_s.

a, b, c, d, and e are coefficients.

The set of coefficients that apply to a vent stream shall be obtained from table 2.

Table 2—Distillation NSPS TRE Coefficients for Vent Streams Controlled By a Flare

	a	**b**	**c**	**d**	**e**
$H_T < 11.2$ MJ/scm	2.25	0.288	−0.193	−0.0051	2.08
($H_T < 301$ Btu/scf)	(0.140)	(0.0367)	(−0.000448)	(−0.0051)	(4.59)
$H_T \geq 11.2$ MJ/scm	0.309	0.0619	−0.0043	−0.0034	2.08
($H_T \geq 301$ Btu/scf)	(0.0193)	(0.00788)	(−0.0000010)	(−0.0034)	(4.59)

(g) Each owner or operator of an affected facility seeking to comply with §60.660(c)(4) or §60.662(c) shall recalculate the TRE index value for that affected facility whenever process changes are made. Examples of process changes include changes in production capacity, feedstock type, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. The TRE index value shall be recalculated based on test data, or on best engineering estimates of the effects of the change to the recovery system.

(1) Where the recalculated TRE index value is less than or equal to 1.0, the owner or operator shall notify the Administrator within 1 week of the recalculation and shall conduct a performance test according to the methods and procedures required by §60.664 in order to determine compliance with §60.662(a). Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(2) Where the initial TRE index value is greater than 8.0 and the recalculated TRE index value is less than or equal to 8.0 but greater than 1.0, the owner or operator shall conduct a performance test in accordance with §§60.8 and

60.664 and shall comply with §§60.663, 60.664 and 60.665. Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(h) Any owner or operator subject to the provisions of this subpart seeking to demonstrate compliance with §60.660(c)(6) shall use Method 2, 2A, 2C, or 2D as appropriate, for determination of volumetric flow rate.

[55 FR 26942, June 29, 1990, as amended at 65 FR 61774, Oct. 17, 2000]

§60.665 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to §60.662 shall notify the Administrator of the specific provisions of §60.662 (§60.662 (a), (b), or (c)) with which the owner or operator has elected to comply. Notification shall be submitted with the notification of initial start-up required by §60.7(a)(3). If an owner or operator elects at a later date to use an alternative provision of §60.662 with which he or she will comply, then the Administrator shall be notified by the owner or operator 90 days before implementing a change and, upon implementing the change, a performance test shall be performed as specified by §60.664 within 180 days.

(b) Each owner or operator subject to the provisions of this subpart shall keep an up-to-date, readily accessible record of the following data measured during each performance test, and also include the following data in the report of the initial performance test required under §60.8. Where a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to comply with §60.662(a), a report containing performance test data need not be submitted, but a report containing the information in §60.665(b)(2)(i) is required. The same data specified in this section shall be submitted in the reports of all subsequently required performance tests where either the emission control efficiency of a control device, outlet concentration of TOC, or the TRE index value of a vent stream from a recovery system is determined.

(1) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(a) through use of either a thermal or catalytic incinerator:

(i) The average firebox temperature of the incinerator (or the average temperature upstream and downstream of the catalyst bed for a catalytic incinerator), measured at least every 15 minutes and averaged over the same time period of the performance testing, and

(ii) The percent reduction of TOC determined as specified in §60.664(b) achieved by the incinerator, or the concentration of TOC (ppmv, by compound) determined as specified in §60.664(b) at the outlet of the control device on a dry basis corrected to 3 percent oxygen.

(2) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(a) through use of a boiler or process heater:

(i) A description of the location at which the vent stream is introduced into the boiler or process heater, and

(ii) The average combustion temperature of the boiler or process heater with a design heat input capacity of less than 44 MW (150 million Btu/hr) measured at least every 15 minutes and averaged over the same time period of the performance testing.

(3) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(b) through use of a smokeless flare, flare design (i.e., steam-assisted, air-assisted or nonassisted), all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the performance test, continuous records of the flare pilot flame monitoring, and records of all periods of operations during which the pilot flame is absent.

(4) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(c):

(i) Where an absorber is the final recovery device in the recovery system, the exit specific gravity (or alternative parameter which is a measure of the degree of absorbing liquid saturation, if approved by the Administrator), and average exit temperature, of the absorbing liquid measured at least every 15 minutes and averaged over the same time period of the performance testing (both measured while the vent stream is normally routed and constituted), or

(ii) Where a condenser is the final recovery device in the recovery system, the average exit (product side) temperature measured at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is routed and constituted normally, or

(iii) Where a carbon adsorber is the final recovery device in the recovery system, the total steam mass flow measured at least every 15 minutes and averaged over the same time period of the performance test (full carbon bed cycle), temperature of the carbon bed after regeneration (and within 15 minutes of completion of any cooling cycle(s)), and duration of the carbon bed steaming cycle (all measured while the vent stream is routed and constituted normally), or

(iv) As an alternative to §60.665(b)(4) ((i), (ii) or (iii), the concentration level or reading indicated by the organics monitoring device at the outlet of the absorber, condenser, or carbon adsorber, measured at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is normally routed and constituted.

(v) All measurements and calculations performed to determine the TRE index value of the vent stream.

(c) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.663 (a) and (c) as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where a combustion device is used to comply with §60.662(a), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) For thermal incinerators, all 3-hour periods of operation during which the average combustion temperature was more than 28 °C (50 °F) below the average combustion temperature during the most recent performance test at which compliance with §60.662(a) was determined.

(2) For catalytic incinerators, all 3-hour periods of operation during which the average temperature of the vent stream immediately before the catalyst bed is more than 28 °C (50 °F) below the average temperature of the vent stream during the most recent performance test at which compliance with §60.662(a) was determined. The owner or operator also shall record all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 percent of the average temperature difference of the device during the most recent performance test at which compliance with §60.662(a) was determined.

(3) All 3-hour periods of operation during which the average combustion temperature was more than 28 °C (50 °F) below the average combustion temperature during the most recent performance test at which compliance with §60.662(a) was determined for boilers or process heaters with a design heat input capacity of less than 44 MW (150 million Btu/hr).

(4) For boilers or process heaters, whenever there is a change in the location at which the vent stream is introduced into the flame zone as required under §60.662(a).

(d) Each owner or operator subject to the provisions of this subpart shall keep up to date, readily accessible continuous records of the flow indication specified under §60.663(a)(2), §60.663(b)(2) and §60.663(c)(1), as well as up-to-date, readily accessible records of all periods when the vent stream is diverted from the control device or has no flow rate.

(e) Each owner or operator subject to the provisions of this subpart who uses a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater to comply with §60.662(a) shall keep an up-to-date, readily accessible record of all periods of operation of the boiler or process heater. (Examples of such records could include records of steam use, fuel use, or monitoring data collected pursuant to other State or Federal regulatory requirements.)

(f) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the flare pilot flame monitoring specified under §60.663(b), as well as up-to-date, readily accessible records of all periods of operations in which the pilot flame is absent.

(g) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.663(e), as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where an owner or operator seeks to comply with §60.662(c), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) Where an absorber is the final recovery device in a recovery system, and where an organic compound monitoring device is not used:

(i) All 3-hour periods of operation during which the average absorbing liquid temperature was more than 11 °C (20 °F) above the average absorbing liquid temperature during the most recent performance test, or

(ii) All 3-hour periods of operation during which the average absorbing liquid specific gravity was more than 0.1 unit above, or more than 0.1 unit below, the average absorbing liquid specific gravity during the most recent performance test (unless monitoring of an alternative parameter, which is a measure of the degree of absorbing liquid saturation, is approved by the Administrator, in which case he will define appropriate parameter boundaries and periods of operation during which they are exceeded).

(2) Where a condenser is the final recovery device in a system, and where an organic compound monitoring device is not used, all 3-hour periods of operation during which the average exit (product side) condenser operating temperature was more than 6 °C (1 1 °F) above the average exit (product side) operating temperature during the most recent performance test.

(3) Where a carbon adsorber is the final recovery device in a system, and where an organic compound monitoring device is not used:

(i) All carbon bed regeneration cycles during which the total mass steam flow was more than 10 percent below the total mass steam flow during the most recent performance test, or

(ii) All carbon bed regeneration cycles during which the temperature of the carbon bed after regeneration (and after completion of any cooling cycle(s)) was more than 10 percent greater than the carbon bed temperature (in degrees Celsius) during the most recent performance test.

(4) Where an absorber, condenser, or carbon adsorber is the final recovery device in the recovery system and where an organic compound monitoring device is used, all 3-hour periods of operation during which the average organic compound concentration level or reading of organic compounds in the exhaust gases is more than 20 percent greater than the exhaust gas organic compound concentration level or reading measured by the monitoring device during the most recent performance test.

(h) Each owner or operator of an affected facility subject to the provisions of this subpart and seeking to demonstrate compliance with §60.662(c) shall keep up-to-date, readily accessible records of:

(1) Any changes in production capacity, feedstock type, or catalyst type, or of any replacement, removal or addition of recovery equipment or a distillation unit;

(2) Any recalculation of the TRE index value performed pursuant to §60.664(g); and

(3) The results of any performance test performed pursuant to the methods and procedures required by §60.664(e).

(i) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the flow rate cutoff in §60.660(c)(6) shall keep up-to-date, readily accessible records to indicate that the vent stream flow rate is less than 0.008 scm/min (0.3 scf/min) and of any change in equipment or process operation that increases the operating vent stream flow rate, including a measurement of the new vent stream flow rate.

(j) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the design production capacity provision in §60.660(c)(5) shall keep up-to-date, readily accessible records of any change in equipment or process operation that increases the design production capacity of the process unit in which the affected facility is located.

(k) Each owner and operator subject to the provisions of this subpart is exempt from the quarterly reporting requirements contained in §60.7(c) of the General Provisions.

(l) Each owner or operator that seeks to comply with the requirements of this subpart by complying with the requirements of §60.660 (c)(4), (c)(5), or (c)(6) or §60.662 shall submit to the Administrator semiannual reports of the following recorded information. The initial report shall be submitted within 6 months after the initial start-up date.

(1) Exceedances of monitored parameters recorded under §60.665 (c) and (g).

(2) All periods recorded under §60.665(d) when the vent stream is diverted from the control device or has no flow rate.

(3) All periods recorded under §60.665(e) when the boiler or process heater was not operating.

(4) All periods recorded under §60.665(f) in which the pilot flame of the flare was absent.

(5) Any change in equipment or process operation that increases the operating vent stream flow rate above the low flow exemption level in §60.660(c)(6), including a measurement of the new vent stream flow rate, as recorded under §60.665(i). These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed with the same time period to verify the recalculated flow value and to obtain the vent stream characteristics of heating value and E_{TOC}. The performance test is subject to the requirements of §60.8 of the General Provisions. Unless the facility qualifies for an exemption under the low capacity exemption status in §60.660(c)(5), the facility must begin compliance with the requirements set forth in §60.662.

(6) Any change in equipment or process operation, as recorded under paragraph (j) of this section, that increases the design production capacity above the low capacity exemption level in §60.660(c)(5) and the new capacity resulting from the change for the distillation process unit containing the affected facility. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, and E_{TOC}. The performance test is subject to the requirements of §60.8. The facility must begin compliance with the requirements set forth in §60.660(d) or §60.662. If the facility chooses to comply with §60.662, the facility may qualify for an exemption in §60.660(c)(4) or (6).

(7) Any recalculation of the TRE index value, as recorded under §60.665(h).

(m) The requirements of §60.665(l) remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with §60.665(l), provided that they comply with the requirements established by the State.

(n) Each owner or operator that seeks to demonstrate compliance with §60.660(c)(5) must submit to the Administrator an initial report detailing the design production capacity of the process unit.

(o) Each owner or operator that seeks to demonstrate compliance with §60.660(c)(6) must submit to the Administrator an initial report including a flow rate measurement using the test methods specified in §60.664.

(p) The Administrator will specify appropriate reporting and recordkeeping requirements where the owner or operator of an affected facility complies with the standards specified under §60.662 other than as provided under §60.663(a), (b), (c) and (d).

[55 FR 26922, June 29, 1990; 55 FR 36932, Sept. 7, 1990, as amended at 60 FR 58237, Nov. 27, 1995; 65 FR 61778, Oct. 17, 2000; 65 FR 78279, Dec. 14, 2000; 79 FR 11251, Feb. 27, 2014]

§60.666 Reconstruction.

For purposes of this subpart “fixed capital cost of the new components,” as used in §60.15, 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 December 30, 1983. 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 undertake and complete, within a reasonable time, a continuous program of component replacement.

§60.667 Chemicals affected by subpart NNN.

Chemical name	**CAS No.***
Acetaldehyde	75-07-0
Acetaldol	107-89-1
Acetic acid	64-19-7
Acetic anhydride	108-24-7
Acetone	67-64-1
Acetone cyanohydrin	75-86-5
Acetylene	74-86-2
Acrylic acid	79-10-7
Acrylonitrile	107-13-1
Adipic acid	124-04-9
Adiponitrile	111-69-3
Alcohols, C-11 or lower, mixtures	
Alcohols, C-12 or higher, mixtures	
Allyl chloride	107-05-1
Amylene	513-35-9
Amylenes, mixed	
Aniline	62-53-3
Benzene	71-43-2
Benzenesulfonic acid	98-11-3
Benzenesulfonic acid C_{10-16}-alkyl derivatives, sodium salts	68081-81-2
Benzoic acid, tech	65-85-0
Benzyl chloride	100-44-7
Biphenyl	92-52-4

Chemical name	**CAS No.***
Bisphenol A	80-05-7
Brometone	76-08-4
1,3-Butadiene	106-99-0
Butadiene and butene fractions	
n-Butane	106-97-8
1,4-Butanediol	110-63-4
Butanes, mixed	
1-Butene	106-98-9
2-Butene	25167-67-3
Butenes, mixed	
n-Butyl acetate	123-86-4
Butyl acrylate	141-32-2
n-Butyl alcohol	71-36-3
sec-Butyl alcohol	78-92-2
tert-Butyl alcohol	75-65-0
Butylbenzyl phthalate	85-68-7
Butylene glycol	107-88-0
tert-Butyl hydroperoxide	75-91-2
2-Butyne-1,4-diol	110-65-6
Butyraldehyde	123-72-8
Butyric anhydride	106-31-0
Caprolactam	105-60-2
Carbon disulfide	75-15-0
Carbon tetrabromide	558-13-4
Carbon tetrachloride	56-23-5
Chlorobenzene	108-90-7
2-Chloro-4-(ethylamino)-6-(isopropylamino)-s-triazine	1912-24-9
Chloroform	67-66-3
p-Chloronitrobenzene	100-00-5
Chloroprene	126-99-8
Citric acid	77-92-9
Crotonaldehyde	4170-30-0
Crotonic acid	3724-65-0
Cumene	98-82-8
Cumene hydroperoxide	80-15-9

Chemical name	**CAS No.***
Cyanuric chloride	108-77-0
Cyclohexane	110-82-7
Cyclohexane, oxidized	68512-15-2
Cyclohexanol	108-93-0
Cyclohexanone	108-94-1
Cyclohexanone oxime	100-64-1
Cyclohexene	110-83-8
1,3-Cyclopentadiene	542-92-7
Cyclopropane	75-19-4
Diacetone alcohol	123-42-2
Dibutanized aromatic concentrate	
1,4-Dichlorobutene	110-57-6
3,4-Dichloro-1-butene	64037-54-3
Dichlorodifluoromethane	75-71-8
Dichlorodimethylsilane	75-78-5
Dichlorofluoromethane	75-43-4
-Dichlorohydrin	96-23-1
Diethanolamine	111-42-2
Diethylbenzene	25340-17-4
Diethylene glycol	111-46-6
Di-n-heptyl-n-nonyl undecyl phthalate	85-68-7
Di-isodecyl phthalate	26761-40-0
Diisononyl phthalate	28553-12-0
Dimethylamine	124-40-3
Dimethyl terephthalate	120-61-6
2,4-Dinitrotoluene	121-14-2
2,4-(and 2,6)-dinitrotoluene	121-14-2
	606-20-2
Dioctyl phthalate	117-81-7
Dodecene	25378-22-7
Dodecylbenzene, non linear	
Dodecylbenzenesulfonic acid	27176-87-0
Dodecylbenzenesulfonic acid, sodium salt	25155-30-0
Epichlorohydrin	106-89-8
Ethanol	64-17-5

Chemical name	**CAS No.***
Ethanolamine	141-43-5
Ethyl acetate	141-78-6
Ethyl acrylate	140-88-5
Ethylbenzene	100-41-4
Ethyl chloride	75-00-3
Ethyl cyanide	107-12-0
Ethylene	74-85-1
Ethylene dibromide	106-93-4
Ethylene dichloride	107-06-2
Ethylene glycol	107-21-1
Ethylene glycol monobutyl	111-76-2
Ethylene glycol monoethyl ether	110-80-5
Ethylene glycol monoethyl ether acetate	111-15-9
Ethylene glycol monomethyl ether	109-86-4
Ethylene oxide	75-21-8
2-Ethylhexanal	26266-68-2
2-Ethylhexyl alcohol	104-76-7
(2-Ethylhexyl) amine	104-75-6
Ethylmethylbenzene	25550-14-5
6-Ethyl-1,2,3,4-tetrahydro 9,10-anthracenedione	15547-17-8
Formaldehyde	50-00-0
Glycerol	56-81-5
n-Heptane	142-82-5
Heptenes (mixed)	
Hexadecyl chloride	
Hexamethylene diamine	124-09-4
Hexamethylene diamine adipate	3323-53-3
Hexamethylenetetramine	100-97-0
Hexane	110-54-3
2-Hexenedinitrile	13042-02-9
3-Hexenedinitrile	1119-85-3
Hydrogen cyanide	74-90-8
Isobutane	75-28-5
Isobutanol	78-83-1
Isobutylene	115-11-7

Chemical name	**CAS No.***
Isobutyraldehyde	78-84-2
Isodecyl alcohol	25339-17-7
Isooctyl alcohol	26952-21-6
Isopentane	78-78-4
Isophthalic acid	121-91-5
Isoprene	78-79-5
Isopropanol	67-63-0
Ketene	463-51-4
Linear alcohols, ethoxylated, mixed	
Linear alcohols, ethoxylated, and sulfated, sodium salt, mixed	
Linear alcohols, sulfated, sodium salt, mixed	
Linear alkylbenzene	123-01-3
Magnesium acetate	142-72-3
Maleic anhydride	108-31-6
Melamine	108-78-1
Mesityl oxide	141-79-7
Methacrylonitrile	126-98-7
Methanol	67-56-1
Methylamine	74-89-5
ar-Methylbenzenediamine	25376-45-8
Methyl chloride	74-87-3
Methylene chloride	75-09-2
Methyl ethyl ketone	78-93-3
Methyl iodide	74-88-4
Methyl isobutyl ketone	108-10-1
Methyl methacrylate	80-62-6
2-Methylpentane	107-83-5
1-Methyl-2-pyrrolidone	872-50-4
Methyl tert-butyl ether	
Naphthalene	91-20-3
Nitrobenzene	98-95-3
1-Nonene	27215-95-8
Nonyl alcohol	143-08-8
Nonylphenol	25154-52-3
Nonylphenol, ethoxylated	9016-45-9

Chemical name	**CAS No.***
Octene	25377-83-7
Oil-soluble petroleum sulfonate, calcium salt	
Oil-soluble petroleum sulfonate, sodium salt	
Pentaerythritol	115-77-5
n-Pentane	109-66-0
3-Pentenenitrile	4635-87-4
Pentenes, mixed	109-67-1
Perchloroethylene	127-18-4
Phenol	108-95-2
1-Phenylethyl hydroperoxide	3071-32-7
Phenylpropane	103-65-1
Phosgene	75-44-5
Phthalic anhydride	85-44-9
Propane	74-98-6
Propionaldehyde	123-38-6
Propionic acid	79-09-4
Propyl alcohol	71-23-8
Propylene	115-07-1
Propylene chlorohydrin	78-89-7
Propylene glycol	57-55-6
Propylene oxide	75-56-9
Sodium cyanide	143-33-9
Sorbitol	50-70-4
Styrene	100-42-5
Terephthalic acid	100-21-0
1,1,2,2-Tetrachloroethane	79-34-5
Tetraethyl lead	78-00-2
Tetrahydrofuran	109-99-9
Tetra (methyl-ethyl) lead	
Tetramethyl lead	75-74-1
Toluene	108-88-3
Toluene-2,4-diamine	95-80-7
Toluene-2,4-(and, 2,6)-diisocyanate (80/20 mixture)	26471-62-5
Tribromomethane	75-25-2
1,1,1-Trichloroethane	71-55-6

Chemical name	**CAS No.***
1,1,2-Trichloroethane	79-00-5
Trichloroethylene	79-01-6
Trichlorofluoromethane	75-69-4
1,1,2-Trichloro-1,2,2-trifluoroethane	76-13-1
Triethanolamine	102-71-6
Triethylene glycol	112-27-6
Vinyl acetate	108-05-4
Vinyl chloride	75-01-4
Vinylidene chloride	75-35-4
m-Xylene	108-38-3
o-Xylene	95-47-6
p-Xylene	106-42-3
Xylenes (mixed)	1330-20-7
m-Xylenol	576-26-1

*CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

[55 FR 26942, June 29, 1990, as amended at 60 FR 58237, 58238, Nov. 27, 1995]

§60.668 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under §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: §60.663(e).

Attachment I

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on May 21, 2013]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart QQQ—Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems

Source: 53 FR 47623, Nov. 23, 1988, unless otherwise noted.

§ 60.690 Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities located in petroleum refineries for which construction, modification, or reconstruction is commenced after May 4, 1987.

(2) An individual drain system is a separate affected facility.

(3) An oil-water separator is a separate affected facility.

(4) An aggregate facility is a separate affected facility.

(b) Notwithstanding the provisions of 40 CFR 60.14(e)(2), the construction or installation of a new individual drain system shall constitute a modification to an affected facility described in § 60.690(a)(4). For purposes of this paragraph, a new individual drain system shall be limited to all process drains and the first common junction box.

§ 60.691 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act or in subpart A of 40 CFR part 60, and the following terms shall have the specific meanings given them.

Active service means that a drain is receiving refinery wastewater from a process unit that will continuously maintain a water seal.

Aggregate facility means an individual drain system together with ancillary downstream sewer lines and oil-water separators, down to and including the secondary oil-water separator, as applicable.

Catch basin means an open basin which serves as a single collection point for stormwater runoff received directly from refinery surfaces and for refinery wastewater from process drains.

Closed vent system means a system that is not open to the atmosphere and that is composed of piping, connections, and, if necessary, flow-inducing devices that transport gas or vapor from an emission source to a control device. If gas or vapor from regulated equipment are routed to a process (e.g., to a petroleum refinery fuel gas system), the process shall not be considered a closed vent system and is not subject to the closed vent system standards.

Completely closed drain system means an individual drain system that is not open to the atmosphere and is equipped and operated with a closed vent system and control device complying with the requirements of § 60.692-5.

Control device means an enclosed combustion device, vapor recovery system or flare.

Fixed roof means a cover that is mounted to a tank or chamber in a stationary manner and which does not move with fluctuations in wastewater levels.

Floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface.

Gas-tight means operated with no detectable emissions.

Individual drain system means all process drains connected to the first common downstream junction box. The term includes all such drains and common junction box, together with their associated sewer lines and other junction boxes, down to the receiving oil-water separator.

Junction box means a manhole or access point to a wastewater sewer system line.

No detectable emissions means less than 500 ppm above background levels, as measured by a detection instrument in accordance with Method 21 in appendix A of 40 CFR part 60.

Non-contact cooling water system means a once-through drain, collection and treatment system designed and operated for collecting cooling water which does not come into contact with hydrocarbons or oily wastewater and which is not recirculated through a cooling tower.

Oil-water separator means wastewater treatment equipment used to separate oil from water consisting of a separation tank, which also includes the forebay and other separator basins, skimmers, weirs, grit chambers, and sludge hoppers. Slop oil facilities, including tanks, are included in this term along with storage vessels and auxiliary equipment located between individual drain systems and the oil-water separator. This term does not include storage vessels or auxiliary equipment which do not come in contact with or store oily wastewater.

Oily wastewater means wastewater generated during the refinery process which contains oil, emulsified oil, or other hydrocarbons. Oily wastewater originates from a variety of refinery processes including cooling water, condensed stripping steam, tank draw-off, and contact process water.

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

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

Sewer line means a lateral, trunk line, branch line, ditch, channel, or other conduit used to convey refinery wastewater to downstream components of a refinery wastewater treatment system. This term does not include buried, below-grade sewer lines.

Slop oil means the floating oil and solids that accumulate on the surface of an oil-water separator.

Storage vessel means any tank, reservoir, or container used for the storage of petroleum liquids, including oily wastewater.

Stormwater sewer system means a drain and collection system designed and operated for the sole purpose of collecting stormwater and which is segregated from the process wastewater collection system.

Wastewater system means any component, piece of equipment, or installation that receives, treats, or processes oily wastewater from petroleum refinery process units.

Water seal controls means a seal pot, p-leg trap, or other type of trap filled with water that has a design capability to create a water barrier between the sewer and the atmosphere.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995]

§ 60.692-1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of §§ 60.692-1 to 60.692-5 and with §§ 60.693-1 and 60.693-2, except during periods of startup, shutdown, or malfunction.

(b) Compliance with §§ 60.692-1 to 60.692-5 and with §§ 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 § 60.696.

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

(d)(1) Stormwater sewer systems are not subject to the requirements of this subpart.

(2) Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily wastewater, is not subject to the requirements of this subpart.

(3) Non-contact cooling water systems are not subject to the requirements of this subpart.

(4) An owner or operator shall demonstrate compliance with the exclusions in paragraphs (d)(1), (2), and (3) of this section as provided in § 60.697 (h), (i), and (j).

§ 60.692-2 Standards: Individual drain systems.

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

(2) Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.

(3) Except as provided in paragraph (a)(4) of this section, each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions.

(4) As an alternative to the requirements in paragraph (a)(3) of this section, if an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of service, inspections shall be conducted initially and semiannually to ensure caps or plugs are in place and properly installed.

(5) Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in § 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 thereafter 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 § 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 § 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.

§ 60.692-3 Standards: Oil-water separators.

(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 § 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 § 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 § 60.692-5, except as provided in paragraph (c) of this section or in § 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 § 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 §§ 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.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995; 65 FR 61778, Oct. 17, 2000]

§ 60.692-4 Standards: Aggregate facility.

A new, modified, or reconstructed aggregate facility shall comply with the requirements of §§ 60.692-2 and 60.692-3.

§ 60.692-5 Standards: Closed vent systems and control devices.

(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 °C (1,500 °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 § 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 § 60.692-6.

§ 60.692-6 Standards: Delay of repair.

(a) Delay of repair of facilities that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial refinery or process unit shutdown.

(b) Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.

§ 60.692-7 Standards: Delay of compliance.

(a) Delay of compliance of modified individual drain systems with ancillary downstream treatment components will be allowed if compliance with the provisions of this subpart cannot be achieved without a refinery or process unit shutdown.

(b) Installation of equipment necessary to comply with the provisions of this subpart shall occur no later than the next scheduled refinery or process unit shutdown.

§ 60.693-1 Alternative standards for individual drain systems.

(a) An owner or operator may elect to construct and operate a completely closed drain system.

(b) Each completely closed drain system shall be equipped and operated with a closed vent system and control device complying with the requirements of § 60.692-5.

(c) An owner or operator must notify the Administrator in the report required in 40 CFR 60.7 that the owner or operator has elected to construct and operate a completely closed drain system.

(d) If an owner or operator elects to comply with the provisions of this section, then the owner or operator does not need to comply with the provisions of § 60.692-2 or § 60.694.

(e)(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 § 60.692-6.

§ 60.693-2 Alternative standards for oil-water separators.

(a) An owner or operator may elect to construct and operate a floating roof on an oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart which meets the following specifications.

(1) Each floating roof shall be equipped with a closure device between the wall of the separator and the roof edge. The closure device is to consist of a primary seal and a secondary seal.

(i) The primary seal shall be a liquid-mounted seal or a mechanical shoe seal.

(A) A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the separator and the floating roof. A mechanical shoe seal means a metal sheet held vertically against the wall of the separator 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.

(B) The gap width between the primary seal and the separator wall shall not exceed 3.8 cm (1.5 in.) at any point.

(C) The total gap area between the primary seal and the separator wall shall not exceed 67 cm^2 /m (3.2 $in.^2$ /ft) of separator wall perimeter.

(ii) The secondary seal shall be above the primary seal and cover the annular space between the floating roof and the wall of the separator.

(A) The gap width between the secondary seal and the separator wall shall not exceed 1.3 cm (0.5 in.) at any point.

(B) The total gap area between the secondary seal and the separator wall shall not exceed 6.7 cm^2 /m (0.32 $in.^2$ /ft) of separator wall perimeter.

(iii) The maximum gap width and total gap area shall be determined by the methods and procedures specified in § 60.696(d).

(A) Measurement of primary seal gaps shall be performed within 60 calendar days after initial installation of the floating roof and introduction of refinery wastewater and once every 5 years thereafter.

(B) Measurement of secondary seal gaps shall be performed within 60 calendar days of initial introduction of refinery wastewater and once every year thereafter.

(iv) The owner or operator shall make necessary repairs within 30 calendar days of identification of seals not meeting the requirements listed in paragraphs (a)(1) (i) and (ii) of this section.

(2) Except as provided in paragraph (a)(4) of this section, each opening in the roof shall be equipped with a gasketed cover, seal, or lid, which shall be maintained in a closed position at all times, except during inspection and maintenance.

(3) The roof shall be floating on the liquid (i.e., off the roof supports) at all times except during abnormal conditions (i.e., low flow rate).

(4) The floating roof may be equipped with one or more emergency roof drains for removal of stormwater. Each emergency roof drain shall be fitted with a slotted membrane fabric cover that covers at least 90 percent of the drain opening area or a flexible fabric sleeve seal.

(5)(i) Access doors and other openings shall be visually inspected initially and semiannually thereafter to ensure that there is a tight fit around the edges and to identify other problems that could result in VOC emissions.

(ii) When a broken seal or gasket on an access door or other opening is identified, it shall be repaired as soon as practicable, but not later than 30 calendar days after it is identified, except as provided in § 60.692-6.

(b) An owner or operator must notify the Administrator in the report required by 40 CFR 60.7 that the owner or operator has elected to construct and operate a floating roof under paragraph (a) of this section.

(c) For portions of the oil-water separator tank where it is infeasible to construct and operate a floating roof, such as the skimmer mechanism and weirs, a fixed roof meeting the requirements of § 60.692-3(a) shall be installed.

(d) Except as provided in paragraph (c) of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator does not need to comply with the provisions of §§ 60.692-3 or 60.694 applicable to the same facilities.

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995]

§ 60.694 Permission to use alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved by the applicable requirement in § 60.692, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

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

(c) Any person seeking permission under this section shall collect, verify, and submit to the Administrator information showing that the alternative means achieves equivalent emission reductions.

§ 60.695 Monitoring of operations.

(a) Each owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator.

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

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995; 65 FR 61778, Oct. 17, 2000]

§ 60.696 Performance test methods and procedures and compliance provisions.

(a) Before using any equipment installed in compliance with the requirements of § 60.692-2, § 60.692-3, § 60.692-4, § 60.692-5, or § 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 owner or operator of each source that is equipped with a closed vent system and control device as required in § 60.692-5 (other than a flare) is exempt from § 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 owner or operator shall conduct a performance test initially, and at other times as requested by the Administrator, using the test methods and procedures in § 60.18(f) to determine compliance of flares.

(d) After installing the control equipment required to meet § 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 § 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 § 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.

§ 60.697 Recordkeeping requirements.

(a) Each owner or operator 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 § 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 § 60.692-2, the location, date, and corrective action shall be recorded for inspections required by § 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 §§ 60.692-2 and 60.693-1(e), the location, date, and corrective action shall be recorded for inspections required by §§ 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 § 60.692-3, the location, date, and corrective action shall be recorded for inspections required by § 60.692-3(a) when a problem is identified that could result in VOC emissions.

(d) For closed vent systems subject to § 60.692-5 and completely closed drain systems subject to § 60.693-1, the location, date, and corrective action shall be recorded for inspections required by § 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 § 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 °C (1,500 °F) is used to meet the 95-percent requirement, documentation that those conditions exist is sufficient to meet the requirements of this paragraph.

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

(iii) Periods when the closed vent systems and control devices required in § 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 § 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 §§ 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 owner or operator 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 °C (50 °F) below the design combustion zone temperature, and shall keep such records for 2 years after the information is recorded.

(ix) Each owner or operator 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 °C (50 °F) below the design gas stream temperature, and records of all 3-hour periods during which the average temperature difference across the catalyst bed is less than 80 percent of the design temperature difference, and shall keep such records for 2 years after the information is recorded.

(x) Each owner or operator 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 owner or operator 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 an owner or operator 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 § 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 § 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 § 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 § 60.693-2, the location, date, and corrective action shall be recorded for inspections required by §§ 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 § 60.693-2(a)(1)(iii)(A), ten years after the information is recorded.

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

[53 FR 47623, Nov. 23, 1985, as amended at 60 FR 43259, Aug. 18, 1995; 65 FR 61778, Oct. 17, 2000]

§ 60.698 Reporting requirements.

(a) An owner or operator electing to comply with the provisions of § 60.693 shall notify the Administrator of the alternative standard selected in the report required in § 60.7.

(b)(1) Each owner or operator 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 owner or operator of an affected facility that uses a flare shall submit to the Administrator within 60 days after initial startup, as required under § 60.8(a), a report of the results of the performance test required in § 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 the Administrator.

(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 °C (50 °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 °C (50 °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 § 60.695(a)(3)(ii).

(e) If compliance with the provisions of this subpart is delayed pursuant to § 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.

[53 FR 47623, Nov. 23, 1988, as amended at 60 FR 43260, Aug. 18, 1995]

§ 60.699 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:

§ 60.694 Permission to use alternative means of emission limitations.

[53 FR 47623, Nov. 23, 1985]

Attachment J

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on June 2, 2014]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart RRR—Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes

SOURCE: 58 FR 45962, Aug. 31, 1993, unless otherwise noted.

§60.700 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to each affected facility designated in paragraph (b) of this section that is part of a process unit that produces any of the chemicals listed in §60.707 as a product, co-product, by-product, or intermediate, except as provided in paragraph (c) of this section.

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after June 29, 1990:

(1) Each reactor process not discharging its vent stream into a recovery system.

(2) Each combination of a reactor process and the recovery system into which its vent stream is discharged.

(3) Each combination of two or more reactor processes and the common recovery system into which their vent streams are discharged.

(c) Exemptions from the provisions of paragraph (a) of this section are as follows:

(1) Any reactor process that is designed and operated as a batch operation is not an affected facility.

(2) Each affected facility that has a total resource effectiveness (TRE) index value greater than 8.0 is exempt from all provisions of this subpart except for §§60.702(c); 60.704 (d), (e), and (f); and 60.705 (g), (l)(1), (l)(6), and (t).

(3) Each affected facility in a process unit with a total design capacity for all chemicals produced within that unit of less than 1 gigagram per year (1,100 tons per year) is exempt from all provisions of this subpart except for the recordkeeping and reporting requirements in §60.705 (i), (l)(5), and (n).

(4) Each affected facility operated with a vent stream flow rate less than 0.011 scm/min is exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in §60.704(g) and §70.705 (h), (l)(4), and (o).

(5) If the vent stream from an affected facility is routed to a distillation unit subject to subpart NNN and has no other releases to the air except for a pressure relief valve, the facility is exempt from all provisions of this subpart except for §60.705(r).

(6) Any reactor process operating as part of a process unit which produces beverage alcohols, or which uses, contains, and produces no VOC is not an affected facility.

(7) Any reactor process that is subject to the provisions of subpart DDD is not an affected facility.

(8) Each affected facility operated with a concentration of total organic compounds (TOC) (less methane and ethane) in the vent stream less than 300 ppmv as measured by Method 18 or a concentration of TOC in the vent stream less than 150 ppmv as measured by Method 25A is exempt from all provisions of this subpart except for the test method and procedure and the reporting and recordkeeping requirements in §60.704(h) and paragraphs (j), (l)(8), and (p) of §60.705.

(d) *Alternative means of compliance*—(1) *Option to comply with part 65.* Owners or operators of process vents that are subject to this subpart may choose to comply with the provisions of 40 CFR part 65, subpart D, to satisfy the requirements of §§60.702 through 60.705 and 60.708. The provisions of 40 CFR part 65 also satisfy the criteria of paragraphs (c)(2), (4), and (8) of this section. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart D, 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 process vents. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (d)(2) do not apply to owners or operators of process vents complying with 40 CFR part 65, subpart D, 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 D, must comply with 40 CFR part 65, subpart A.

(3) *Compliance date.* Owners or operators who choose to comply with 40 CFR part 65, subpart D at initial startup shall comply with paragraphs (d)(1) and (2) of this section for each vent stream on and after the date on which the initial performance test 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 the initial startup, whichever date comes first.

(4) *Initial startup notification.* Each owner or operator subject to the provisions of this subpart that chooses to comply with 40 CFR part 65, subpart D, at initial startup shall notify the Administrator of the specific provisions of 40 CFR 65.63(a)(1), (2), or (3), with which the owner or operator has elected to comply. Notification shall be submitted with the notifications of initial startup required by 40 CFR 65.5(b).

(NOTE: The intent of these standards is to minimize emissions of VOC through the application of best demonstrated technology (BDT). The numerical emission limits in these standards are expressed in terms of TOC, measured as TOC less methane and ethane. This emission limit reflects the performance of BDT.)

[58 FR 45962, Aug. 31, 1993, as amended at 60 FR 58238, Nov. 27, 1995; 65 FR 78279, Dec. 14, 2000]

§60.701 Definitions.

As used in this subpart, all terms not defined here shall have the meaning given them in the Act and in subpart A of part 60, and the following terms shall have the specific meanings given them.

Batch operation means any noncontinuous reactor process that is not characterized by steady-state conditions and in which reactants are not added and products are not removed simultaneously.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator.

By compound means by individual stream components, not carbon equivalents.

Car-seal means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Combustion device means an individual unit of equipment, such as an incinerator, flare, boiler, or process heater, used for combustion of a vent stream discharged from the process vent.

Continuous recorder means a data recording device recording an instantaneous data value at least once every 15 minutes.

Flame zone means the portion of the combustion chamber in a boiler occupied by the flame envelope.

Flow indicator means a device which indicates whether gas flow is present in a line.

Halogenated vent stream means any vent stream determined to have a total concentration (by volume) of compounds containing halogens of 20 ppmv (by compound) or greater.

Incinerator means an enclosed combustion device that is used for destroying organic compounds. If there is energy recovery, the energy recovery section and the combustion chambers are not of integral design. That is, the energy recovery section and the combustion section are not physically formed into one manufactured or assembled unit but are joined by ducts or connections carrying flue gas.

Primary fuel means the fuel fired through a burner or a number of similar burners. The primary fuel provides the principal heat input to the device, and the amount of fuel is sufficient to sustain operation without the addition of other fuels.

Process heater means a device that transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water.

Process unit means equipment assembled and connected by pipes or ducts to produce, as intermediates or final products, one or more of the chemicals in §60.707. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient product storage facilities.

Product means any compound or chemical listed in §60.707 which is produced for sale as a final product as that chemical, or for use in the production of other chemicals or compounds. By-products, co-products, and intermediates are considered to be products.

Reactor processes are unit operations in which one or more chemicals, or reactants other than air, are combined or decomposed in such a way that their molecular structures are altered and one or more new organic compounds are formed.

Recovery device means an individual unit of equipment, such as an absorber, carbon adsorber, or condenser, capable of and used for the purpose of recovering chemicals for use, reuse, or sale.

Recovery system means an individual recovery device or series of such devices applied to the same vent stream.

Relief valve means a valve used only to release an unplanned, nonroutine discharge. A relief valve discharge results from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.

Secondary fuel means a fuel fired through a burner other than a primary fuel burner. The secondary fuel may provide supplementary heat in addition to the heat provided by the primary fuel.

Total organic compounds or TOC means those compounds measured according to the procedures in §60.704(b)(4). For the purposes of measuring molar composition as required in §60.704(d)(2)(i) and §60.704(d)(2)(ii), hourly emission rate as required in §60.704(d)(5) and §60.704(e), and TOC concentration as required in §60.705(b)(4) and §60.705(f)(4), those compounds which the Administrator has determined do not contribute appreciably to the formation of ozone are to be excluded.

Total resource effectiveness or TRE index value means a measure of the supplemental total resource requirement per unit reduction of TOC associated with a vent stream from an affected reactor process facility, based on vent stream flow rate, emission rate of TOC, net heating value, and corrosion properties (whether or not the vent stream contains halogenated compounds), as quantified by the equation given under §60.704(e).

Vent stream means any gas stream discharged directly from a reactor process to the atmosphere or indirectly to the atmosphere after diversion through other process equipment. The vent stream excludes relief valve discharges and equipment leaks.

§60.702 Standards.

Each owner or operator of any affected facility shall comply with paragraph (a), (b), or (c) of this section for each vent stream on and after the date on which the initial performance test required by §60.8 and §60.704 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 the initial start-up, whichever date comes first. Each owner or operator shall either:

(a) Reduce emissions of TOC (less methane and ethane) by 98 weight-percent, or to a TOC (less methane and ethane) concentration of 20 ppmv, on a dry basis corrected to 3 percent oxygen, whichever is less stringent. If a boiler or process heater is used to comply with this paragraph, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or

(b) Combust the emissions in a flare that meets the requirements of §60.18; or

(c) Maintain a TRE index value greater than 1.0 without use of a VOC emission control device.

§60.703 Monitoring of emissions and operations.

(a) The owner or operator of an affected facility that uses an incinerator to seek to comply with the TOC emission limit specified under §60.702(a) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment:

(1) A temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater.

(i) Where an incinerator other than a catalytic incinerator is used, a temperature monitoring device shall be installed in the firebox or in the ductwork immediately downstream of the firebox in a position before any substantial heat exchange is encountered.

(ii) Where a catalytic incinerator is used, temperature monitoring devices shall be installed in the gas stream immediately before and after the catalyst bed.

(2) A flow indicator that provides a record of vent stream flow diverted from being routed to the incinerator at least once every 15 minutes for each affected facility, except as provided in paragraph (a)(2)(ii) of this section.

(i) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream from being routed to the incinerator, resulting in its emission to the atmosphere.

(ii) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(b) The owner or operator of an affected facility that uses a flare to seek to comply with §60.702(b) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment:

(1) A heat sensing device, such as an ultraviolet beam sensor or thermocouple, at the pilot light to indicate the continuous presence of a flame.

(2) A flow indicator that provides a record of vent stream flow diverted from being routed to the flare at least once every 15 minutes for each affected facility, except as provided in paragraph (b)(2)(ii) of this section.

(i) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream from being routed to the flare, resulting in its emission to the atmosphere.

(ii) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(c) The owner or operator of an affected facility that uses a boiler or process heater to seek to comply with §60.702(a) shall install, calibrate, maintain and operate according to the manufacturer's specifications the following equipment:

(1) A flow indicator that provides a record of vent stream flow diverted from being routed to the boiler or process heater at least once every 15 minutes for each affected facility, except as provided in paragraph (c)(1)(ii) of this section.

(i) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream from being routed to the boiler or process heater, resulting in its emission to the atmosphere.

(ii) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(2) A temperature monitoring device in the firebox equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater, for boilers or process heaters of less than 44 MW (150 million Btu/hr) design heat input capacity. Any vent stream introduced with primary fuel into a boiler or process heater is exempt from this requirement.

(d) The owner or operator of an affected facility that seeks to demonstrate compliance with the TRE index value limit specified under §60.702(c) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator:

(1) Where an absorber is the final recovery device in the recovery system:

(i) A scrubbing liquid temperature monitoring device having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater, and a specific gravity monitoring device having an accuracy of ±0.02 specific gravity units, each equipped with a continuous recorder; or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(2) Where a condenser is the final recovery device in the recovery system:

(i) A condenser exit (product side) temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater; or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(3) Where a carbon adsorber is the final recovery device unit in the recovery system:

(i) An integrating steam flow monitoring device having an accuracy of ±10 percent, and a carbon bed temperature monitoring device having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater, both equipped with a continuous recorder; or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(e) An owner or operator of an affected facility seeking to demonstrate compliance with the standards specified under §60.702 with a control device other than an incinerator, boiler, process heater, or flare; or a recovery device other than an absorber, condenser, or carbon adsorber, shall provide to the Administrator information describing the operation of the control device or recovery device and the process parameter(s) which would indicate proper operation and maintenance of the device. The Administrator may request further information and will specify appropriate monitoring procedures or requirements.

§60.704 Test methods and procedures.

(a) For the purpose of demonstrating compliance with §60.702, all affected facilities shall be run at full operating conditions and flow rates during any performance test.

(b) The following methods in appendix A to this part, except as provided under §60.8(b), shall be used as reference methods to determine compliance with the emission limit or percent reduction efficiency specified under §60.702(a).

(1) Method 1 or 1A, as appropriate, for selection of the sampling sites. The control device inlet sampling site for determination of vent stream molar composition or TOC (less methane and ethane) reduction efficiency shall be prior to the inlet of the control device and after the recovery system.

(2) Method 2, 2A, 2C, or 2D, as appropriate, for determination of the gas volumetric flow rates.

(3) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the oxygen concentration ($\%O_{2d}$) for the purposes of determining compliance with the 20 ppmv limit. The sampling site shall be the same as that of the TOC samples, and the samples shall be taken during the same time that the TOC samples are taken. The TOC concentration corrected to 3 percent O_2 (C_c) shall be computed using the following equation:

$$C_C = C_{TOC} \frac{17.9}{20.9 - \%O_{2d}}$$

where:

C_c = Concentration of TOC corrected to 3 percent O_2, dry basis, ppm by volume.

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

$\%O_{2d}$ = Concentration of O_2, dry basis, percent by volume.

(4) Method 18 to determine the concentration of TOC in the control device outlet and the concentration of TOC in the inlet when the reduction efficiency of the control device is to be determined.

(i) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately 15-minute intervals.

(ii) The emission reduction (R) of TOC (minus methane and ethane) shall be determined using the following equation:

$$R = \frac{E_i - E_o}{E_i} \times 100$$

where:

R=Emission reduction, percent by weight.

E_i = Mass rate of TOC entering the control device, kg TOC/hr.

E_o = Mass rate of TOC discharged to the atmosphere, kg TOC/hr.

(iii) The mass rates of TOC (E_i, E_o) shall be computed using the following equations:

$$E_i = K_2 \sum_{j=1}^{n} C_{ij} M_{ij} Q_i$$

$$E_i = K_2 \sum_{j=1}^{n} C_{oj} M_{ij} Q_o$$

where:

C_{ij}. C_{oj} = Concentration of sample component "j" of the gas stream at the inlet and outlet of the control device, respectively, dry basis, ppm by volume.

M_{ij}, M_{oj} = Molecular weight of sample component "j" of the gas stream at the inlet and outlet of the control device, respectively, g/g-mole (lb/lb-mole).

Q_i, Q_o = Flow rate of gas stream at the inlet and outlet of the control device, respectively, dscm/min (dscf/hr).

K_2 = Constant, 2.494×10^{-6} (l/ppm) (g-mole/scm) (kg/g) (min/hr), where standard temperature for (g-mole/scm) is 20 °C.

(iv) The TOC concentration (C_{TOC}) is the sum of the individual components and shall be computed for each run using the following equation:

$$C_{TOC} = \sum_{j=1}^{n} C_j$$

where:

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

C_j = Concentration of sample components "j", dry basis, ppm by volume.

n=Number of components in the sample.

(5) The requirement for an initial performance test is waived, in accordance with §60.8(b), for the following:

(i) When a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to seek compliance with §60.702(a).

(ii) When a vent stream is introduced into a boiler or process heater with the primary fuel.

(iii) The Administrator reserves the option to require testing at such other times as may be required, as provided for in section 114 of the Act.

(6) For purposes of complying with the 98 weight-percent reduction in §60.702(a), if the vent stream entering a boiler or process heater with a design capacity less than 44 MW (150 million Btu/hour) is introduced with the combustion air or as secondary fuel, the weight-percent reduction of TOC (minus methane and ethane) across the combustion device shall be determined by comparing the TOC (minus methane and ethane) in all combusted vent streams, primary fuels, and secondary fuels with the TOC (minus methane and ethane) exiting the combustion device.

(c) When a flare is used to seek to comply with §60.702(b), the flare shall comply with the requirements of §60.18.

(d) The following test methods in appendix A to this part, except as provided under §60.8(b), shall be used for determining the net heating value of the gas combusted to determine compliance under §60.702(b) and for determining the process vent stream TRE index value to determine compliance under §60.700(c)(2) and §60.702(c).

(1)(i) Method 1 or 1A, as appropriate, for selection of the sampling site. The sampling site for the vent stream flow rate and molar composition determination prescribed in §60.704 (d)(2) and (d)(3) shall be, except for the situations outlined in paragraph (d)(1)(ii) of this section, prior to the inlet of any control device, prior to any postreactor dilution of the stream with air, and prior to any postreactor introduction of halogenated compounds into the process vent stream. No traverse site selection method is needed for vents smaller than 4 inches in diameter.

(ii) If any gas stream other than the reactor vent stream is normally conducted through the final recovery device:

(A) The sampling site for vent stream flow rate and molar composition shall be prior to the final recovery device and prior to the point at which any nonreactor stream or stream from a nonaffected reactor process is introduced.

(B) The efficiency of the final recovery device is determined by measuring the TOC concentration using Method 18 at the inlet to the final recovery device after the introduction of any vent stream and at the outlet of the final recovery device.

(C) This efficiency of the final recovery device shall be applied to the TOC concentration measured prior to the final recovery device and prior to the introduction of any nonreactor stream or stream from a nonaffected reactor process to determine the concentration of TOC in the reactor process vent stream from the final recovery device. This concentration of TOC is then used to perform the calculations outlined in §60.704(d) (4) and (5).

(2) The molar composition of the process vent stream shall be determined as follows:

(i) Method 18 to measure the concentration of TOC including those containing halogens.

(ii) ASTM D1946-77 or 90 (Reapproved 1994) (incorporation by reference as specified in §60.17 of this part) to measure the concentration of carbon monoxide and hydrogen.

(iii) Method 4 to measure the content of water vapor.

(3) The volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D, as appropriate.

(4) The net heating value of the vent stream shall be calculated using the following equation:

$$H_T = K_1 \sum_{j=1}^{n} C_j H_j \quad 1 - B_{ws}$$

where:

H_T = Net heating value of the sample, MJ/scm, where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C, as in the definition of Q_s (vent stream flow rate).

K_1 = Constant, 1.740×10^{-7} (l/ppm) (g-mole/scm) (MJ/kcal), where standard temperature for (g-mole/scm) is 20 °C.

C_j = Concentration on a dry basis of compound j in ppm, as measured for organics by Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (incorporation by reference as specified in §60.17 of this part) as indicated in §60.704(d)(2).

H_j = Net heat of combustion of compound j, kcal/g-mole, based on combustion at 25 °C and 760 mm Hg. The heats of combustion of vent stream components would be required to be determined using ASTM D2382-76 or 88 or D4809-95 (incorporation by reference as specified in §60.17 of this part) if published values are not available or cannot be calculated.

B_{ws} = Water vapor content of the vent stream, proportion by volume.

(5) The emission rate of TOC in the vent stream shall be calculated using the following equation:

$$E_{TOC} = K_2 \sum_{j=1}^{n} C_j M_j Q_s$$

where:

E_{TOC} = Emission rate of TOC in the sample, kg/hr.

K_2 = Constant, 2.494×10^{-6} (l/ppm) (g-mole/scm) (kg/g) (min/hr), where standard temperature for (g-mole/scm) is 20 °C.

C_j = Concentration on a dry basis of compound j in ppm as measured by Method 18 as indicated in §60.704(d)(2).

M_j = Molecular weight of sample j, g/g-mole.

Q_s = Vent stream flow rate (dscm/min) at a temperature of 20 °C.

(6) The total vent stream concentration (by volume) of compounds containing halogens (ppmv, by compound) shall be summed from the individual concentrations of compounds containing halogens which were measured by Method 18.

(e) For purposes of complying with §60.700(c)(2) and §60.702(c), the owner or operator of a facility affected by this subpart shall calculate the TRE index value of the vent stream using the equation for incineration in paragraph (e)(1) of this section for halogenated vent streams. The owner or operator of an affected facility with a nonhalogenated vent stream shall determine the TRE index value by calculating values using both the incinerator equation in (e)(1) of this section and the flare equation in (e)(2) of this section and selecting the lower of the two values.

(1) The equation for calculating the TRE index value of a vent stream controlled by an incinerator is as follows:

$$TRE = \frac{1}{E_{TOC}} \left[a + b\left(Q_s\right)^{0.88} + c\left(Q_s\right) + d\left(Q_s\right)\left(H_T\right) + e\left(Q_s\right)^{0.88}\left(H_T\right)^{0.88} + f\left(Y_s\right)^{0.5} \right]$$

(i) Where for a vent stream flow rate (scm/min) at a standard temperature of 20 °C that is greater than or equal to 14.2 scm/min:

TRE=TRE index value.

Q_s = Vent stream flow rate (scm/min) at a standard temperature of 20 °C.

H_T = Vent stream net heating value (MJ/scm), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C as in the definition of Q_s.

$Y_s = Q_s$ for all vent stream categories listed in table 1 except for Category E vent streams where $Y_s = (Q_s)(H_T)/3.6$.

E_{TOC} = Hourly emissions of TOC reported in kg/hr.

a, b, c, d, e, and f are coefficients. The set of coefficients that apply to a vent stream can be obtained from table 1.

Table 1—Total Resource Effectiveness Coefficients for Vent Streams Controlled by an Incinerator Subject to the New Source Performance Standards for Reactor Processes

	a	b	c	d	e	f
DESIGN CATEGORY A1. FOR HALOGENATED PROCESS VENT STREAMS, IF 0≤NET HEATING VALUE (MJ/scm)≤3.5: Q_s = *Vent Stream Flow Rate (scm/min)*						
$14.2 \le Q_s \le 18.8$	19.18370	0.27580	0.75762	−0.13064	0	0.01025
$18.8 < Q_s \le 699$	20.00563	0.27580	0.30387	−0.13064	0	0.01025
$699 < Q_s \le 1{,}400$	39.87022	0.29973	0.30387	−0.13064	0	0.01449
$1{,}400 < Q_s \le 2{,}100$	59.73481	0.31467	0.30387	−0.13064	0	0.01775
$2{,}100 < Q_s \le 2{,}800$	79.59941	0.32572	0.30387	−0.13064	0	0.02049
$2{,}800 < Q_s \le 3{,}500$	99.46400	0.33456	0.30387	−0.13064	0	0.02291
DESIGN CATEGORY A2. FOR HALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE (MJ/scm)>3.5: Q_s = *Vent Stream Flow Rate (scm/min)*						
$14.2 < Q_s \le 18.8$	18.84466	0.26742	−0.20044	0	0	0.01025
$18.8 < Q_s \le 699$	19.66658	0.26742	−0.25332	0	0	0.01025
$699 < Q_s \le 1{,}400$	39.19213	0.29062	−0.25332	0	0	0.01449
$1{,}400 < Q_s \le 2{,}100$	58.71768	0.30511	−0.25332	0	0	0.01775
$2{,}100 < Q_s \le 2{,}800$	78.24323	0.31582	−0 25332	0	0	0.02049
$2{,}800 < Q_s \le 3{,}500$	97.76879	0.32439	−0.25332	0	0	0.02291
DESIGN CATEGORY B. FOR NONHALOGENATED PROCESS VENT STREAMS, IF 0≤NET HEATING VALUE (MJ/scm)≤0.48: Q_s = *Vent Stream Flow Rate (scm/min)*						
$14.2 \le Q_s \le 1{,}340$	8.54245	0.10555	0.09030	−0.17109	0	0.01025
$1{,}340 < Q_s \le 2{,}690$	16.94386	0.11470	0.09030	−0.17109	0	0.01449
$2{,}690 < Q_s \le 4{,}040$	25.34528	0.12042	0.09030	−0.17109	0	0.01775
DESIGN CATEGORY C. FOR NONHALOGENATED PROCESS VENT STREAMS, IF 0.48<NET HEATING VALUE (MJ/scm)≤1.9: Q_s = *Vent Stream Flow Rate (scm/min)*						
$14.2 \le Q_s \le 1{,}340$	9.25233	0.06105	0.31937	−0.16181	0	0.01025
$1{,}340 < Q_s \le 2{,}690$	18.36363	0.06635	0.31937	−0.16181	0	0.01449
$2{,}690 < Q_s \le 4{,}040$	27.47492	0.06965	0.31937	−0.16181	0	0.01775
DESIGN CATEGORY D. FOR NONHALOGENATED PROCESS VENT STREAMS, IF 1.9<NET HEATING VALUE (MJ/scm)≤3.6: Q_s = *Vent Stream Flow Rate (scm/min)*						
$14.2 \le Q_s \le 1{,}180$	6.67868	0.06943	0.02582	0	0	0.01025
$1{,}180 < Q_s \le 2{,}370$	13.21633	0.07546	0.02582	0	0	0.01449
$2{,}370 < Q_s \le 3{,}550$	19.75398	0.07922	0.02582	0	0	0.01755

DESIGN CATEGORY E. FOR NONHALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE (MJ/scm)>3.6: Y_s = *Dilution Flow Rate (scm/min)=(Q_s)* (H_T)/3.6						
$14.2 \le Y_s \le 1{,}180$	6.67868	0	0	−0.00707	0.02220	0.01025
$1{,}180 < Y_s \le 2{,}370$	13.21633	0	0	−0.00707	0.02412	0.01449
$2{,}370 < Y_s \le 3{,}550$	19.75398	0	0	−0.00707	0.02533	0.01755

(ii) For a vent stream flow rate (scm/min) at a standard temperature of 20 °C that is less than 14.2 scm/min:

TRE=TRE index value.

Q_s = 14.2 scm/min.

H_T = (FLOW)(HVAL)/14.2

where the following inputs are used:

FLOW=Vent stream flow rate (scm/min), at a standard temperature of 20 °C.

HVAL=Vent stream net heating value (MJ/scm), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C as in definition of Q_s.

Y_s = 14.2 scm/min for all vent streams except for Category E vent streams, where Y_s = (14.2)(H_T)/3.6.

E_{TOC} = Hourly emissions of TOC reported in kg/hr.

a, b, c, d, e, and f are coefficients. The set of coefficients that apply to a vent stream can be obtained from table 1.

(2) The equation for calculating the TRE index value of a vent stream controlled by a flare is as follows:

$$TRE = \frac{1}{E_{TOC}}\left[a\left(Q_s\right)+b\left(Q_s\right)^{0.8}+c\left(Q_s\right)\left(H_T\right)+d\left(E_{TOC}\right)+e\right]$$

where:

TRE=TRE index value.

E_{TOC} = Hourly emission rate of TOC reported in kg/hr.

Q_s = Vent stream flow rate (scm/min) at a standard temperature of 20 °C.

H_T = Vent stream net heating value (MJ/scm) where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C as in the definition of Q_s.

a, b, c, d, and e are coefficients. The set of coefficients that apply to a vent stream can be obtained from table 2.

Table 2—Total Resource Effectiveness Coefficients for Vent Streams Controlled by a Flare Subject to the New Source Performance Standards for Reactor Processes

	a	**b**	**c**	**d**	**e**

H_T<11.2 MJ/scm	2.25	0.288	−0.193	−0.0051	2.08
H_T≥11.2 MJ/scm	0.309	0.0619	−0.0043	−0.0034	2.08

(f) Each owner or operator of an affected facility seeking to comply with §60.700(c)(2) or §60.702(c) shall recalculate the TRE index value for that affected facility whenever process changes are made. Examples of process changes include changes in production capacity, feedstock type, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. The TRE index value shall be recalculated based on test data, or on best engineering estimates of the effects of the change on the recovery system.

(1) Where the recalculated TRE index value is less than or equal to 1.0, the owner or operator shall notify the Administrator within 1 week of the recalculation and shall conduct a performance test according to the methods and procedures required by §60.704 in order to determine compliance with §60.702 (a) or (b). Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(2) Where the recalculated TRE index value is less than or equal to 8.0 but greater than 1.0, the owner or operator shall conduct a performance test in accordance with §60.8 and §60.704 and shall comply with §60.703, §60.704 and §60.705. Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(g) Any owner or operator subject to the provisions of this subpart seeking to demonstrate compliance with §60.700(c)(4) shall use Method 2, 2A, 2C, or 2D of appendix A to 40 CFR part 60, as appropriate, for determination of volumetric flow rate.

(h) Each owner or operator seeking to demonstrate that a reactor process vent stream has a TOC concentration for compliance with the low concentration exemption in §60.700(c)(8) shall conduct an initial test to measure TOC concentration.

(1) The sampling site shall be selected as specified in paragraph (d)(1)(i) of this section.

(2) Method 18 or Method 25A of part 60, appendix A shall be used to measure concentration.

(3) Where Method 18 is used to qualify for the low concentration exclusion in §60.700(c)(8), the procedures in §60.704(b)(4) (i) and (iv) shall be used to measure TOC concentration, and the procedures of §60.704(b)(3) shall be used to correct the TOC concentration to 3 percent oxygen. To qualify for the exclusion, the results must demonstrate that the concentration of TOC, corrected to 3 percent oxygen, is below 300 ppm by volume.

(4) Where Method 25A is used, the following procedures shall be used to calculate ppm by volume TOC concentration, corrected to 3 percent oxygen:

(i) Method 25A shall be used only if a single organic compound is greater than 50 percent of total TOC, by volume, in the reactor process vent stream. This compound shall be the principal organic compound.

(ii) The principal organic compound may be determined by either process knowledge or test data collected using an appropriate EPA Reference Method. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current reactor process vent stream conditions.

(iii) The principal organic compound shall be used as the calibration gas for Method 25A.

(iv) The span value for Method 25A shall be 300 ppmv.

(v) Use of Method 25A is acceptable if the response from the high-level calibration gas is at least 20 times the standard deviation of the response from the zero calibration gas when the instrument is zeroed on the most sensitive scale.

(vi) The owner or operator shall demonstrate that the concentration of TOC including methane and ethane measured by Method 25A, corrected to 3 percent oxygen, is below 150 ppm by volume to qualify for the low concentration exclusion in §60.700(c)(8).

(vii) The concentration of TOC shall be corrected to 3 percent oxygen using the procedures and equation in paragraph (b)(3) of this section.

[58 FR 45962, Aug. 31, 1993, as amended at 60 FR 58238, Nov. 27, 1995; 65 FR 61778, Oct. 17, 2000]

§60.705 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to §60.702 shall notify the Administrator of the specific provisions of §60.702 (§60.702 (a), (b), or (c)) with which the owner or operator has elected to comply. Notification shall be submitted with the notification of initial start-up required by §60.7(a)(3). If an owner or operator elects at a later date to use an alternative provision of §60.702 with which he or she will comply, then the Administrator shall be notified by the owner or operator 90 days before implementing a change and, upon implementing the change, a performance test shall be performed as specified by §60.704 no later than 180 days from initial start-up.

(b) Each owner or operator subject to the provisions of this subpart shall keep an up-to-date, readily accessible record of the following data measured during each performance test, and also include the following data in the report of the initial performance test required under §60.8. Where a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used or where the reactor process vent stream is introduced as the primary fuel to any size boiler or process heater to comply with §60.702(a), a report containing performance test data need not be submitted, but a report containing the information in §60.705(b)(2)(i) is required. The same data specified in this section shall be submitted in the reports of all subsequently required performance tests where either the emission control efficiency of a combustion device, outlet concentration of TOC, or the TRE index value of a vent stream from a recovery system is determined.

(1) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.702(a) through use of either a thermal or catalytic incinerator:

(i) The average firebox temperature of the incinerator (or the average temperature upstream and downstream of the catalyst bed for a catalytic incinerator), measured at least every 15 minutes and averaged over the same time period of the performance testing, and

(ii) The percent reduction of TOC determined as specified in §60.704(b) achieved by the incinerator, or the concentration of TOC (ppmv, by compound) determined as specified in §60.704(b) at the outlet of the control device on a dry basis corrected to 3 percent oxygen.

(2) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.702(a) through use of a boiler or process heater:

(i) A description of the location at which the vent stream is introduced into the boiler or process heater, and

(ii) The average combustion temperature of the boiler or process heater with a design heat input capacity of less than 44 MW (150 million Btu/hr) measured at least every 15 minutes and averaged over the same time period of the performance testing.

(3) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.702(b) through use of a smokeless flare, flare design (i.e., steam-assisted, air-assisted or nonassisted), all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the performance test, continuous records of the flare pilot flame monitoring, and records of all periods of operations during which the pilot flame is absent.

(4) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.702(c):

(i) Where an absorber is the final recovery device in the recovery system, the exit specific gravity (or alternative parameter which is a measure of the degree of absorbing liquid saturation, if approved by the Administrator), and average exit temperature, of the absorbing liquid measured at least every 15 minutes and averaged over the same time period of the performance testing (both measured while the vent stream is normally routed and constituted); or

(ii) Where a condenser is the final recovery device in the recovery system, the average exit (product side) temperature measured at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is routed and constituted normally; or

(iii) Where a carbon adsorber is the final recovery device in the recovery system, the total steam mass flow measured at least every 15 minutes and averaged over the same time period of the performance test (full carbon bed cycle), temperature of the carbon bed after regeneration [and within 15 minutes of completion of any cooling cycle(s)], and duration of the carbon bed steaming cycle (all measured while the vent stream is routed and constituted normally); or

(iv) As an alternative to §60.705(b)(4) (i), (ii) or (iii), the concentration level or reading indicated by the organics monitoring device at the outlet of the absorber, condenser, or carbon adsorber, measured at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is normally routed and constituted.

(v) All measurements and calculations performed to determine the TRE index value of the vent stream.

(c) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.703 (a) and (c) as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where a combustion device is used to comply with §60.702(a), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) For thermal incinerators, all 3-hour periods of operation during which the average combustion temperature was more than 28 °C (50 °F) below the average combustion temperature during the most recent performance test at which compliance with §60.702(a) was determined.

(2) For catalytic incinerators, all 3-hour periods of operation during which the average temperature of the vent stream immediately before the catalyst bed is more than 28 °C (50 °F) below the average temperature of the vent stream during the most recent performance test at which compliance with §60.702(a) was determined. The owner or operator also shall record all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 percent of the average temperature difference of the bed during the most recent performance test at which compliance with §60.702(a) was determined.

(3) All 3-hour periods of operation during which the average combustion temperature was more than 28 °C (50 °F) below the average combustion temperature during the most recent performance test at which compliance with §60.702(a) was determined for boilers or process heaters with a design heat input capacity of less than 44 MW (150 million Btu/hr) where the vent stream is introduced with the combustion air or as a secondary fuel.

(4) For boilers or process heaters, whenever there is a change in the location at which the vent stream is introduced into the flame zone as required under §60.702(a).

(d) Each owner or operator subject to the provisions of this subpart shall keep records of the following:

(1) Up-to-date, readily accessible continuous records of the flow indication specified under §60.703(a)(2)(i), §60.703(b)(2)(i) and §60.703(c)(1)(i), as well as up-to-date, readily accessible records of all periods and the duration when the vent stream is diverted from the control device.

(2) Where a seal mechanism is used to comply with §60.703(a)(2)(ii), §60.703(b)(2)(ii), and §60.703(c)(1)(ii), a record of continuous flow is not required. In such cases, the owner or operator shall keep up-to-date, readily accessible records of all monthly visual inspections of the seals as well as readily accessible records of all periods and the

duration when the seal mechanism is broken, the bypass line valve position has changed, the serial number of the broken car-seal has changed, or when the key for a lock-and-key type configuration has been checked out.

(e) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the flare pilot flame monitoring specified under §60.703(b), as well as up-to-date, readily accessible records of all periods of operations in which the pilot flame is absent.

(f) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.703(d), as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where an owner or operator seeks to comply with §60.702(c), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) Where an absorber is the final recovery device in a recovery system, and where an organic compound monitoring device is not used:

(i) All 3-hour periods of operation during which the average absorbing liquid temperature was more than 11 °C (20 °F) above the average absorbing liquid temperature during the most recent performance test, or

(ii) All 3-hour periods of operation during which the average absorbing liquid specific gravity was more than 0.1 unit above, or more than 0.1 unit below, the average absorbing liquid specific gravity during the most recent performance test (unless monitoring of an alternative parameter, which is a measure of the degree of absorbing liquid saturation, is approved by the Administrator, in which case he will define appropriate parameter boundaries and periods of operation during which they are exceeded).

(2) Where a condenser is the final recovery device in a system, and where an organic compound monitoring device is not used, all 3-hour periods of operation during which the average exit (product side) condenser operating temperature was more than 6 °C (11 °F) above the average exit (product side) operating temperature during the most recent performance test.

(3) Where a carbon adsorber is the final recovery device in a system, and where an organic compound monitoring device is not used:

(i) All carbon bed regeneration cycles during which the total mass steam flow was more than 10 percent below the total mass steam flow during the most recent performance test, or

(ii) All carbon bed regeneration cycles during which the temperature of the carbon bed after regeneration (and after completion of any cooling cycle(s)) was more than 10 percent or 5 °C greater, whichever is less stringent, than the carbon bed temperature (in degrees Celsius) during the most recent performance test.

(4) Where an absorber, condenser, or carbon adsorber is the final recovery device in the recovery system and where an organic compound monitoring device is used, all 3-hour periods of operation during which the average organic compound concentration level or reading of organic compounds in the exhaust gases is more than 20 percent greater than the exhaust gas organic compound concentration level or reading measured by the monitoring device during the most recent performance test.

(g) Each owner or operator of an affected facility subject to the provisions of this subpart and seeking to demonstrate compliance with §60.702(c) shall keep up-to-date, readily accessible records of:

(1) Any changes in production capacity, feedstock type, or catalyst type, or of any replacement, removal or addition of recovery equipment or reactors;

(2) Any recalculation of the TRE index value performed pursuant to §60.704(f); and

(3) The results of any performance test performed pursuant to the methods and procedures required by §60.704(d).

(h) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the flow rate cutoff in §60.700(c)(4) shall keep up-to-date, readily accessible records to indicate that the vent stream flow rate is less than 0.011 scm/min and of any change in equipment or process operation that increases the operating vent stream flow rate, including a measurement of the new vent stream flow rate.

(i) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the design production capacity provision in §60.700(c)(3) shall keep up-to-date, readily accessible records of any change in equipment or process operation that increases the design production capacity of the process unit in which the affected facility is located.

(j) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the low concentration exemption in §60.700(c)(8) shall keep up-to-date, readily accessible records of any change in equipment or process operation that increases the concentration of the vent stream of the affected facility.

(k) Each owner or operator subject to the provisions of this subpart is exempt from the quarterly reporting requirements contained in §60.7(c) of the General Provisions.

(l) Each owner or operator that seeks to comply with the requirements of this subpart by complying with the requirements of §60.700 (c)(2), (c)(3), or (c)(4) or §60.702 shall submit to the Administrator semiannual reports of the following recorded information. The initial report shall be submitted within 6 months after the initial start-up date.

(1) Exceedances of monitored parameters recorded under §60.705 (c), (f), and (g).

(2) All periods and duration recorded under §60.705(d) when the vent stream is diverted from the control device to the atmosphere.

(3) All periods recorded under §60.705(f) in which the pilot flame of the flare was absent.

(4) Any change in equipment or process operation that increases the operating vent stream flow rate above the low flow exemption level in §60.700(c)(4), including a measurement of the new vent stream flow rate, as recorded under §60.705(i). These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed within the same time period to verify the recalculated flow value and to obtain the vent stream characteristics of heating value and $E_{TOC.}$ The performance test is subject to the requirements of §60.8 of the General Provisions. Unless the facility qualifies for an exemption under any of the exemption provisions listed in §60.700(c), except for the total resource effectiveness index greater than 8.0 exemption in §60.700(c)(2), the facility must begin compliance with the requirements set forth in §60.702.

(5) Any change in equipment or process operation, as recorded under paragraph (i) of this section, that increases the design production capacity above the low capacity exemption level in §60.700(c)(3) and the new capacity resulting from the change for the reactor process unit containing the affected facility. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, and $E_{TOC.}$ The performance test is subject to the requirements of §60.8. The facility must begin compliance with the requirements set forth in §60.702 or §60.700(d). If the facility chooses to comply with §60.702, the facility may qualify for an exemption under §60.700(c)(2), (4), or (8).

(6) Any recalculation of the TRE index value, as recorded under §60.705(g).

(7) All periods recorded under §60.705(d) in which the seal mechanism is broken or the by-pass line valve position has changed. A record of the serial number of the car-seal or a record to show that the key to unlock the bypass line valve was checked out must be maintained to demonstrate the period, the duration, and frequency in which the bypass line was operated.

(8) Any change in equipment or process operation that increases the vent stream concentration above the low concentration exemption level in §60.700(c)(8), including a measurement of the new vent stream concentration, as recorded under §60.705(j). These must be reported as soon as possible after the change and no later than 180 days

after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. If the vent stream concentration is above 300 ppmv as measured using Method 18 or above 150 ppmv as measured using Method 25A, a performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, and E_{TOC}. The performance test is subject to the requirements of §60.8 of the General Provisions. Unless the facility qualifies for an exemption under any of the exemption provisions listed in §60.700(c), except for the TRE index greater than 8.0 exemption in §60.700(c)(2), the facility must begin compliance with the requirements set forth in §60.702.

(m) The requirements of §60.705(l) remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with §60.705(l), provided that they comply with the requirements established by the State.

(n) Each owner or operator that seeks to demonstrate compliance with §60.700(c)(3) must submit to the Administrator an initial report detailing the design production capacity of the process unit.

(o) Each owner or operator that seeks to demonstrate compliance with §60.700(c)(4) must submit to the Administrator an initial report including a flow rate measurement using the test methods specified in §60.704.

(p) Each owner or operator that seeks to demonstrate compliance with §60.700(c)(8) must submit to the Administrator an initial report including a concentration measurement using the test method specified in §60.704.

(q) The Administrator will specify appropriate reporting and recordkeeping requirements where the owner or operator of an affected facility complies with the standards specified under §60.702 other than as provided under §60.703 (a), (b), (c), and (d).

(r) Each owner or operator whose reactor process vent stream is routed to a distillation unit subject to subpart NNN and who seeks to demonstrate compliance with §60.700(c)(5) shall submit to the Administrator a process design description as part of the initial report. This process design description must be retained for the life of the process. No other records or reports would be required unless process changes are made.

(s) Each owner or operator who seeks to demonstrate compliance with §60.702 (a) or (b) using a control device must maintain on file a schematic diagram of the affected vent streams, collection system(s), fuel systems, control devices, and bypass systems as part of the initial report. This schematic diagram must be retained for the life of the system.

(t) Each owner or operator that seeks to demonstrate compliance with §60.700(c)(2) must maintain a record of the initial test for determining the total resource effectiveness index and the results of the initial total resource effectiveness index calculation.

[58 FR 45962, Aug. 31, 1993, as amended at 60 FR 58238, Nov. 27, 1995; 65 FR 78279, Dec. 14, 2000]

§60.706 Reconstruction.

(a) For purposes of this subpart “fixed capital cost of the new components,” as used in §60.15, 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 June 29, 1990. 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 undertake and complete, within a reasonable time, a continuous program of component replacement.

(b) [Reserved]

§60.707 Chemicals affected by subpart RRR.

Chemical	CAS No.[1]
Acetaldehyde	75-07-0

Chemical	**CAS No.**[1]
Acetic acid	64-19-7
Acetic anhydride	108-24-7
Acetone	67-64-1
Acetone cyanohydrin	75-86-5
Acetylene	74-86-2
Acrylic acid	79-10-7
Acrylonitrile	107-13-1
Adipic acid	124-04-9
Adiponitrile	111-69-3
Alcohols, C-11 or lower, mixtures	
Alcohols, C-12 or higher, mixtures	
Alcohols, C-12 or higher, unmixed	
Allyl chloride	107-05-1
Amylene	513-35-9
Amylenes, mixed	
Aniline	62-53-3
Benzene	71-43-2
Benzenesulfonic acid	98-11-3
Benzenesulfonic acid C_{10-16}-alkyl derivatives, sodium salts	68081-81-2
Benzyl chloride	100-44-7
Bisphenol A	80-05-7
Brometone	76-08-4
1,3-Butadiene	106-99-0
Butadiene and butene fractions	
n-Butane	106-97-8
1,4-Butanediol	110-63-4
Butanes, mixed	
1-Butene	106-98-9
2-Butene	25167-67-3
Butenes, mixed	
n-Butyl acetate	123-86-4
Butyl acrylate	141-32-2
n-Butyl alcohol	71-36-3
sec-Butyl alcohol	78-92-2
tert-Butyl alcohol	75-65-0
Butylbenzyl phthalate	85-68-7
tert-Butyl hydroperoxide	75-91-2
2-Butyne-1,4-diol	110-65-6
Butyraldehyde	123-72-8
Butyric anhydride	106-31-0
Caprolactam	105-60-2
Carbon disulfide	75-15-0
Carbon tetrachloride	56-23-5
Chloroacetic acid	79-11-8

Chemical	CAS No.[1]
Chlorobenzene	108-90-7
Chlorodifluoromethane	75-45-6
Chloroform	67-66-3
p-Chloronitrobenzene	100-00-5
Citric acid	77-92-9
Cumene	98-82-8
Cumene hydroperoxide	80-15-9
Cyanuric chloride	108-77-0
Cyclohexane	110-82-7
Cyclohexane, oxidized	68512-15-2
Cyclohexanol	108-93-0
Cyclohexanone	108-94-1
Cyclohexanone oxime	100-64-1
Cyclohexene	110-83-8
Cyclopropane	75-19-4
Diacetone alcohol	123-42-2
1,4-Dichlorobutene	110-57-6
3,4-Dichloro-1-butene	64037-54-3
Dichlorodifluoromethane	75-71-8
Dichlorodimethylsilane	75-78-5
Dichlorofluoromethane	75-43-4
Diethanolamine	111-42-2
Diethylbenzene	25340-17-4
Diethylene glycol	111-46-6
Di-isodecyl phthalate	26761-40-0
Dimethyl terephthalate	120-61-6
2,4-(and 2,6)-dinitrotoluene	121-14-2
	606-20-2
Dioctyl phthalate	117-81-7
Dodecene	25378-22-7
Dodecylbenzene, nonlinear	
Dodecylbenzenesulfonic acid	27176-87-0
Dodecylbenzenesulfonic acid, sodium salt	25155-30-0
Epichlorohydrin	106-89-8
Ethanol	64-17-5
Ethanolamine	141-43-5
Ethyl acetate	141-78-6
Ethyl acrylate	140-88-5
Ethylbenzene	100-41-4
Ethyl chloride	75-00-3
Ethylene	74-85-1
Ethylene dibromide	106-93-4
Ethylene dichloride	107-06-2
Ethylene glycol	107-21-1

Chemical	CAS No.[1]
Ethylene glycol monobutyl ether	111-76-2
Ethylene glycol monoethyl ether acetate	111-15-9
Ethylene glycol monomethyl ether	109-86-4
Ethylene oxide	75-21-8
2-Ethylhexyl alcohol	104-76-7
(2-Ethylhexyl) amine	104-75-6
6-Ethyl-1,2,3,4-tetrahydro 9,10-anthracenedione	15547-17-8
Formaldehyde	50-00-0
Glycerol	56-81-5
n-Heptane	142-82-5
Heptenes (mixed)	
Hexamethylene diamine	124-09-4
Hexamethylene diamine adipate	3323-53-3
Hexamethylenetetramine	100-97-0
Hexane	110-54-3
Isobutane	75-28-5
Isobutanol	78-83-1
Isobutylene	115-11-7
Isobutyraldehyde	78-84-2
Isopentane	78-78-4
Isoprene	78-79-5
Isopropanol	67-63-0
Ketene	463-51-4
Linear alcohols, ethoxylated, mixed	
Linear alcohols, ethoxylated, and sulfated, sodium salt, mixed	
Linear alcohols, sulfated, sodium salt, mixed	
Linear alkylbenzene	123-01-3
Maleic anhydride	108-31-6
Mesityl oxide	141-79-7
Methanol	67-56-1
Methylamine	74-39-5
ar-Methylbenzenediamine	25376-45-8
Methyl chloride	74-87-3
Methylene chloride	75-09-2
Methyl ethyl ketone	78-93-3
Methyl isobutyl ketone	108-10-1
Methyl methacrylate	80-62-6
1-Methyl-2-pyrrolidone	872-50-4
Methyl tert-butyl ether	
Naphthalene	91-20-3
Nitrobenzene	98-95-3
1-Nonene	27215-95-8
Nonyl alcohol	143-08-8
Nonylphenol	25154-52-3

Chemical	CAS No.[1]
Nonylphenol, ethoxylated	9016-45-9
Octene	25377-83-7
Oil-soluble petroleum sulfonate, calcium salt	
Pentaerythritol	115-77-5
3-Pentenenitrile	4635-87-4
Pentenes, mixed	109-67-1
Perchloroethylene	127-18-4
Phenol	108-95-2
1-Phenylethyl hydroperoxide	3071-32-7
Phenylpropane	103-65-1
Phosgene	75-44-5
Phthalic anhydride	85-44-9
Propane	74-98-6
Propionaldehyde	123-38-6
Propyl alcohol	71-23-8
Propylene	115-07-1
Propylene glycol	57-55-6
Propylene oxide	75-56-9
Sorbitol	50-70-4
Styrene	100-42-5
Terephthalic acid	100-21-0
Tetraethyl lead	78-00-2
Tetrahydrofuran	109-99-9
Tetra (methyl-ethyl) lead	
Tetramethyl lead	75-74-1
Toluene	108-88-3
Toluene-2,4-diamine	95-80-7
Toluene-2,4-(and, 2,6)-diisocyanate (80/20 mixture)	26471-62-5
1,1,1-Trichloroethane	71-55-6
1,1,2-Trichloroethane	79-00-5
Trichloroethylene	79-01-6
Trichlorofluoromethane	75-69-4
1,1,2-Trichloro-1,2,2-trifluoroethane	76-13-1
Triethanolamine	102-71-6
Triethylene glycol	112-27-6
Vinyl acetate	108-05-4
Vinyl chloride	75-01-4
Vinylidene chloride	75-35-4
m-Xylene	108-38-3
o-Xylene	95-47-6
p-Xylene	106-42-3
Xylenes (mixed)	1330-20-7

[1] CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers

assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

[58 FR 45962, Aug. 31, 1993, as amended at 60 FR 58238, Nov. 27, 1995]

§60.708 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: §60.703(e).

Attachment K

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on September 30, 2014]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

SOURCE: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

Emission Standards for Manufacturers

§60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the Federal Aid Highway System (FAHS); and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

§60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the FAHS; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§60.4203   How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

Emission Standards for Owners and Operators

§60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in §60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in §60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

Fuel Requirements for Owners and Operators

§60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

Other Requirements for Owners and Operators

§60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Compliance Requirements

§60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and (e) and §60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(e) or §60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4204(e) or §60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4212 or §60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

Testing Requirements for Owners and Operators

§60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad (\text{Eq. } 1)$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i = concentration of NO_X or PM at the control device inlet,

C_o = concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\, O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209\, F_d}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm3/J (dscf/106 Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm3/J (dscf/106 Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

Notification, Reports, and Records for Owners and Operators

§60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in §60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

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

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §60.4.

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013]

Special Requirements

§60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in areas of Alaska not accessible by the FAHS may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in sections §§60.4201(f) and 60.4202(g) of this subpart.

(c) Manufacturers, owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the FAHS may choose to meet the applicable emission standards for emergency engines in §60.4202 and §60.4205, and not those for non-emergency engines in §60.4201 and §60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in §60.4201 and §60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

(d) The provisions of §60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS.

(e) The provisions of §60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and §60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011]

§60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4204 or §60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

General Provisions

§60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§60.4219 What definitions apply to this subpart?

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

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in §60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in §60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §60.4211(f)(2)(ii) or (iii) and §60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see “date of manufacture”).

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013]

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X + NMHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)[1]
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1] Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1] For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2] For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3] In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1] Engine speed: ±2 percent of point.

[2] Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:

Each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥ 30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more;	i. Select the sampling port location and number/location of traverse points at the inlet and outlet of the control device;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure O_2 at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.

Each	Complying with the requirement to	You must	Using	According to the following requirements
		iv. Measure NO_X at the inlet and outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	(3) Method 7E of 40 CFR part 60, Appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Each	Complying with the requirement to	You must	Using	According to the following requirements
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine.	(4) Method 5 of 40 CFR part 60, appendix A-3.	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[79 FR 11251, Feb. 27, 2014]

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Attachment L

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on February 1, 2016]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Subpart BB—National Emission Standard for Benzene Emissions From Benzene Transfer Operations

Source: 55 FR 8341, Mar. 7, 1990, unless otherwise noted.

§61.300 Applicability.

(a) The affected facility to which this subpart applies is the total of all loading racks at which benzene is loaded into tank trucks, railcars, or marine vessels at each benzene production facility and each bulk terminal. However, specifically exempted from this regulation are loading racks at which only the following are loaded: Benzene-laden waste (covered under subpart FF of this part), gasoline, crude oil, natural gas liquids, petroleum distillates (e.g., fuel oil, diesel, or kerosene), or benzene-laden liquid from coke by-product recovery plants.

(b) Any affected facility under paragraph (a) of this section which loads only liquid containing less than 70 weight-percent benzene is exempt from the requirements of this subpart, except for the recordkeeping and reporting requirements in §61.305(i).

(c) *Comply with standards at each loading rack.* Any affected facility under paragraph (a) of this section shall comply with the standards in §61.302 or as specified in paragraph (f) of this section, if applicable, at each loading rack that is handling a liquid containing 70 weight-percent or more benzene.

(d) Any affected facility under paragraph (a) of this section whose annual benzene loading is less than 1.3 million liters of 70 weight-percent or more benzene is exempt from the requirements of this subpart, except for the recordkeeping and reporting requirements in §61.305(i).

(e) The owner or operator of an affected facility, as defined in §61.300(a) that loads a marine vessel shall be in compliance with the provisions of this subpart on and after July 23, 1991. If an affected facility that loads a marine vessel also loads a tank truck or railcar, the marine vessel loading racks shall be in compliance with the provisions of this subpart on and after July 23, 1991, while the tank truck loading racks and the railcar loading racks shall be in compliance as required by §61.12.

(f) *Alternative means of compliance*—(1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart E, to satisfy the requirements of §§61.302 through 61.306 for all tank truck or railcar loading racks that are subject to this subpart. Loading racks are referred to as transfer racks in 40 CFR part 65, subpart E. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1. All marine vessel loading racks shall comply with the provisions in §§61.302 through 61.306.

(2) *Part 61, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart E, must also comply with §§61.01, 61.02, 61.05 through 61.08, 61.10(b) through (d), 61.11, and 61.15 for those loading racks. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (f)(2) do not apply to owners or operators of loading racks complying with 40 CFR part 65, subpart E, 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 E, must comply with 40 CFR part 65, subpart A.

[55 FR 8341, Mar. 7, 1990, as amended at 55 FR 45804, Oct. 31, 1990; 65 FR 78284, Dec. 14, 2000]

§61.301 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, or in subpart A or subpart V of part 61.

Bulk terminal means any facility which receives liquid product containing benzene by pipelines, marine vessels, tank trucks, or railcars, and loads the product for further distribution into tank trucks, railcars, or marine vessels.

Car-sealed means having a seal that is placed on the device used to change the position of a valve (e.g., from open to closed) such that the position of the valve cannot be changed without breaking the seal and requiring the replacement of the old seal, once broken, with a new seal.

Control device means all equipment used for recovering or oxidizing benzene vapors displaced from the affected facility.

Incinerator means any enclosed combustion device that is used for destroying organic compounds and that does not extract energy in the form of steam or process heat. These devices do not rely on the heating value of the waste gas to sustain efficient combustion. Auxiliary fuel is burned in the device and the heat from the fuel flame heats the waste gas to combustion temperature. Temperature is controlled by controlling combustion air or fuel.

Leak means any instrument reading of 10,000 ppmv or greater using Method 21 of 40 CFR part 60, appendix A.

Loading cycle means the time period from the beginning of filling a tank truck, railcar, or marine vessel until flow to the control device ceases, as measured by the flow indicator.

Loading rack means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill tank trucks, railcars, or marine vessels.

Marine vessel means any tank ship or tank barge which transports liquid product such as benzene.

Nonvapor tight means any tank truck, railcar, or marine vessel that does not pass the required vapor-tightness test.

Process heater means a device that transfers heat liberated by burning fuel to fluids contained in tubes, except water that is heated to produce steam.

Steam generating unit means any enclosed combustion device that uses fuel energy in the form of steam.

Vapor collection system means any equipment located at the affected facility used for containing benzene vapors displaced during the loading of tank trucks, railcars, or marine vessels. This does not include the vapor collection system that is part of any tank truck, railcar, or marine vessel vapor collection manifold system.

Vapor-tight marine vessel means a marine vessel with a benzene product tank that has been demonstrated within the preceding 12 months to have no leaks. This demonstration shall be made using Method 21 of part 60, appendix A, during the last 20 percent of loading and during a period when the vessel is being loaded at its maximum loading rate. A reading of greater than 10,000 ppm as methane shall constitute a leak. As an alternative, a marine vessel owner or operator may use the vapor-tightness test described in §61.304(f) to demonstrate vapor tightness. A marine vessel operated at negative pressure is assumed to be vapor-tight for the purpose of this standard.

Vapor-tight tank truck or *vapor-tight railcar* means a tank truck or railcar for which it has been demonstrated within the preceding 12 months that its product tank will sustain a pressure change of not more than 750 pascals within 5 minutes after it is pressurized to a minimum of 4,500 pascals. This capability is to be demonstrated using the pressure test procedure specified in Method 27 of appendix A to 40 CFR part 60, and a pressure measurement device which has a precision of ±2.5 mm water and which is capable of measuring above the pressure at which the tank truck or railcar is to be tested for vapor tightness.

[55 FR 8341, Mar. 7, 1990, as amended at 65 FR 62159, Oct. 17, 2000]

§61.302 Standards.

(a) The owner or operator of an affected facility shall equip each loading rack with a vapor collection system that is:

(1) Designed to collect all benzene vapors displaced from tank trucks, railcars, or marine vessels during loading, and

(2) Designed to prevent any benzene vapors collected at one loading rack from passing through another loading rack to the atmosphere.

(b) The owner or operator of an affected facility shall install a control device and reduce benzene emissions routed to the atmosphere through the control device by 98 weight percent. If a boiler or process heater is used to comply with the percent reduction requirement, then the vent stream shall be introduced into the flame zone of such a device.

(c) The owner or operator of an affected facility shall operate any flare used to comply with paragraph (b) of this section in accordance with the requirements of §60.18 (b) through (f).

(d) The owner or operator of an affected facility shall limit loading of benzene into vapor-tight tank trucks and vapor-tight railcars using the following procedures:

(1) The owner or operator shall obtain the vapor-tightness documentation described in §61.305(h) for each tank truck or railcar loaded at the affected facility. The test date in the documentation must be within the preceding 12 months. The vapor-tightness test to be used for tank trucks and railcars is Method 27 of appendix A to 40 CFR part 60.

(2) The owner or operator shall cross-check the identification number for each tank truck or railcar to be loaded with the file of vapor-tightness documentation before the corresponding tank truck or railcar is loaded. If no documentation is on file, the owner or operator shall obtain a copy of the information from the tank truck or railcar operator before the tank truck or railcar is loaded.

(3) Alternate procedures to those described in paragraphs (d)(1) and (d)(2) of this section may be used upon application to, and approval by, the Administrator.

(e) The owner or operator of an affected facility shall limit the loading of marine vessels to those vessels that are vapor tight as determined by either paragraph (e)(1), (e)(2), (e)(3), or (e)(4) of this section.

(1) The owner or operator of an affected facility shall ensure that each marine vessel is loaded with the benzene product tank below atmospheric pressure (i.e., at negative pressure). If the pressure is measured at the interface between the shoreside vapor collection pipe and the marine vessel vapor line, the pressure measured according to the procedures in §61.303(f) must be below atmospheric pressure.

(2) The owner or operator of an affected facility shall use the following procedure to obtain the vapor-tightness documentation described in §61.305(h). The vapor-tightness test for marine vessels is Method 21 of appendix A to 40 CFR part 60, and shall be applied to any potential sources of vapor leaks. A reading of 10,000 ppmv or greater as methane shall constitute a leak.

(i) The owner or operator of an affected facility shall obtain the leak test documentation described in §61.305(h) for each marine vessel prior to loading, if available. The date of the test listed in the documentation must be within the 12 preceding months.

(ii) If there is no documentation of a successful leak test conducted on the marine vessel in the preceding 12 months, the owner or operator of an affected facility shall require that a leak test of the marine vessel be conducted during the final 20 percent of loading of the marine vessel or shall not load the vessel. The test shall be conducted when the marine vessel is being loaded at the maximum allowable loading rate.

(A) If no leak is detected, the owner or operator of an affected facility shall require that the documentation described in §61.305(h) is completed prior to departure of the vessel. The owner or operator of the affected facility shall retain a copy of the vapor-tightness documentation on file.

(B) If any leak is detected, the owner or operator of an affected facility shall require that the vapor-tightness failure be documented for the marine vessel owner or operator prior to departure of the vessel. The owner or operator of the affected facility shall retain a copy of the vapor-tightness documentation on file. Delay of repair of equipment for which leaks have been detected will be allowed if the repair is technically infeasible without dry-docking the vessel. This equipment will be excluded from future Method 21 of appendix A to 40 CFR part 60 tests until repairs are effected. Repair of this equipment shall occur the next time the vessel is dry-docked.

(iii) If the marine vessel has failed its most recent vapor-tightness test as described in §61.302(e)(2)(ii), the owner or operator of the affected facility shall require that the owner or operator of the nonvapor-tight marine vessel provide documentation that the leaks detected during the previous vapor-tightness test have been repaired, or proof that repair is technically infeasible without dry-docking the vessel. Once the repair documentation has been provided, the owner or operator may load the marine vessel. The owner or operator shall require that the vapor-tightness test described in §61.302(e)(2)(ii) be conducted during loading, and shall retain a copy of the vapor-tightness documentation on file.

(3) The owner or operator of an affected facility shall obtain a copy of the marine vessel's vapor-tightness documentation described in §61.305(h) for a test conducted within the preceding 12 months in accordance with §61.304(f).

(4) Alternate procedures to those described in paragraphs (e)(1), (e)(2) and (e)(3) of this section may be used upon application to, and approval by, the Administrator.

(f) The owner or operator of an affected facility shall limit loading of benzene to tank trucks, railcars, and marine vessels equipped with vapor collection equipment that is compatible with the affected facility's vapor collection system.

(g) The owner or operator of an affected facility shall limit loading of tank trucks, railcars, and marine vessels to tank trucks, railcars, and marine vessels whose collection systems are connected to the affected facility's vapor collection systems.

(h) The owner or operator of an affected facility shall ensure that the vapor collection and benzene loading equipment of tank trucks and railcars shall be designed and operated to prevent gauge pressure in the tank truck or railcar tank from exceeding, during loading, the initial pressure the tank was pressured up to and shown to be vapor tight at during the most recent vapor-tightness test using Method 27 of appendix A to 40 CFR part 60. This vapor-tightness test pressure is not to be exceeded when measured by the procedures specified in §61.304(c).

(i) The owner or operator of an affected facility shall ensure that no pressure-vacuum vent in the affected facility's vapor collection system for tank trucks and railcars shall begin to open at a system pressure less than the maximum pressure at which the tank truck or railcar is operated.

(j) The owner or operator of an affected facility shall ensure that the maximum normal operating pressure of the marine vessel's vapor collection equipment shall not exceed 0.8 times the relief set pressure of the pressure-vacuum vents. This level is not to be exceeded when measured by the procedures specified in §61.304(d).

(k) The owner or operator of an affected facility shall inspect the vapor collection system and the control device for detectable emissions, and shall repair any leaks detected, in accordance with §61.242-11 (e) and (f). This inspection of the vapor collection system and control device shall be done during the loading of tank trucks, railcars, or marine vessels.

(l) Vent systems that contain valves that could divert a vent stream from a control device shall have car-sealed opened all valves in the vent system from the emission source to the control device, and car-sealed closed all valves in the vent system that would lead the vent stream to the atmosphere, either directly or indirectly, bypassing the control device.

[55 FR 8341, Mar. 7, 1990, as amended at 65 FR 62159, Oct. 17, 2000]

§61.303 Monitoring requirements.

(a) Each owner or operator of an affected facility that uses an incinerator to comply with the percent reduction requirement specified under §61.302(b) shall install, calibrate, maintain, and operate according to manufacturer's specifications a temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the combustion temperature being measured expressed in degrees Celsius or ±0.5 °C, whichever is greater.

(1) Where an incinerator other than a catalytic incinerator is used, the owner or operator of the affected facility shall install a temperature monitoring device in the firebox.

(2) Where a catalytic incinerator is used, the owner or operator shall install temperature monitoring devices in the gas stream immediately before and after the catalyst bed.

(b) Each owner or operator of an affected facility that uses a flare to comply with §61.302(b) shall install, calibrate, maintain, and operate according to manufacturer's specifications a heat sensing device, such as an ultraviolet beam sensor or thermocouple, at the pilot light to indicate the presence of a flame during the entire loading cycle.

(c) Each owner or operator of an affected facility that uses a steam generating unit or process heater to comply with §61.302(b) shall comply with the following requirements. Where a steam generating unit with a design heat input capacity of less than 44 MW (150 × 10^6 BTU/hr) is used to comply with §61.302(b), the owner or operator of an affected facility shall comply with paragraph (c)(1) of this section. Where a steam generating unit or process heater with a design heat input capacity of 44 MW (150 × 10^6 BTU/hr) or greater is used to comply with §61.302(b), the owner or operator of an affected facility shall comply with paragraph (c)(2) of this section.

(1) Install in the firebox, calibrate, maintain, and operate according to manufacturer's specifications a temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being measured expressed in degrees Celsius or ±0.5 °C, whichever is greater, for steam generating units or process heaters of less than 44 MW (150 × 10^6 BTU/hr) design heat input capacity.

(2) Monitor and record the periods of operation of the steam generating units or process heater if the design heat input capacity of the steam generating unit or process heater is 44 MW (150 × 10^6 BTU/hr) or greater. The records must be readily available for inspection.

(d) Each owner or operator of an affected facility that uses a carbon adsorption system to comply with the percent reduction requirement specified under §61.302(b) shall install, calibrate, maintain, and operate according to manufacturer's specifications a device that continuously indicates and records the concentration or reading of organic compounds in the outlet gas stream of each carbon adsorber bed.

(e) The owner or operator of an affected facility who wishes to demonstrate compliance with the standards specified under §61.302(b) using control devices other than an incinerator, steam generating unit, process heater, carbon adsorber, or flare shall provide the Administrator with 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.

(f) Each owner or operator of an affected facility complying with §61.302(e)(1) shall install, calibrate, maintain, and operate a recording pressure measurement device (magnehelic gauge or equivalent device) and an audible and visible alarm system that is activated when the pressure vacuum specified in §61.302(e)(1) is not attained. The owner or operator shall place the alarm system so that it can be seen and heard where cargo transfer is controlled and on the open deck.

(g) Owners or operators using a vent system that contains valves that could divert a vent stream from a control device used to comply with the provisions of this subpart shall do one or a combination of the following:

(1) Install a flow indicator immediately downstream of each valve that if opened would allow a vent stream to bypass the control device and be emitted, either directly or indirectly, to the atmosphere. The flow indicator shall be capable of recording flow at least once every 15 minutes.

(2) Monitor the valves once a month, checking the position of the valves and the condition of the car seal, and identify all times when the car seals have been broken and the valve position has been changed (*i.e.,* from opened to closed for valves in the vent piping to the control device and from closed to open for valves that allow the stream to be vented directly or indirectly to the atmosphere).

[55 FR 8341, Mar. 7, 1990, as amended at 65 FR 62159, Oct. 17, 2000]

§61.304 Test methods and procedures.

(a) The procedures for determining compliance with §61.302(b) for all control devices other than flares is as follows:

(1) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(2) The time period for a performance test shall be not less than 6 hours, during which at least 300,000 liters of benzene are loaded. If the throughput criterion is not met during the initial 6 hours, the test may be either continued until the throughput criterion is met, or resumed the next day with at least another 6 complete hours of testing.

(3) For intermittent control devices:

(i) The vapor holder level of the intermittent control device shall be recorded at the start of the performance test. The end of the performance test shall coincide with the time when the vapor holder is at its original level.

(ii) At least two startups and shutdowns of the control device shall occur during the performance test. If this does not occur under an automatically controlled operation, the system shall be manually controlled.

(4) An emission testing interval shall consist of each 5-minute period during the performance test. For each interval:

(i) The reading from each measurement instrument shall be recorded.

(ii) Method 1 or 1A of part 60, appendix A, as appropriate, shall be used for selection of the sampling site,

(iii) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D of part 60, appendix A, as appropriate.

(iv) The average benzene concentration upstream and downstream of the control device in the vent shall be determined using Method 25A or Method 25B of appendix A of this part, using benzene as the calibration gas. The average benzene concentration shall correspond to the volume measurement by taking into account the sampling system response time.

(5) The mass emitted during each testing interval shall be calculated as follows:

$M_i = FKV_S\,C$

where:

M_i = Mass of benzene emitted during testing interval i, kg.

V_s = Volume of air-vapor mixture exhausted, m^3 at standard conditions.

C = Benzene concentration (as measured) at the exhaust vent, ppmv.

K = Density, (kg/m^3 benzene), standard conditions.

K = 3.25 for benzene.

F = Conversion factor, (m^3 benzene/m^3 air)(1/ppmv).

F = 10/$^{-6}$/.

s = Standard conditions, 20 °C and 760 mm Hg.

(6) The benzene mass emission rates before and after the control device shall be calculated as follows:

$$E = \frac{\sum_{i=1}^{n} M_i}{T}$$

where:

E = Mass flow rate of benzene emitted, kg/hr.

M_i = Mass of benzene emitted during testing interval i, kg.

T = Total time of all testing intervals, hr.

n = Number of testing intervals.

(7) The percent reduction across the control device shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b}(100)$$

where:

R = Control efficiency of control device, %.

E_b = Mass flow rate of benzene prior to control device, kg/hr.

E_a = Mass flow rate of benzene after control device, kg/hr.

(b) When a flare is used to comply with §61.302(b), a performance test according to Method 22 of appendix A of 40 CFR part 60 shall be performed to determine visible emissions. The observation period shall be at least 2 hours. Performance testing shall be conducted during at least three complete loading cycles with a separate test run for each loading cycle. The observation period for detecting visible emissions shall encompass each loading cycle. Integrated sampling to measure process vent stream flow rate shall be performed continuously during each loading cycle.

(c) For the purpose of determining compliance with §61.302(h), the following procedures shall be used:

(1) Calibrate and install a pressure measurement device (liquid manometer, magnehelic gauge, or equivalent instrument), which has a precision of ±2.5 mm H_20 in the range that the tank truck or railcar was initially pressured to during the most recent vapor-tightness test.

(2) Connect the pressure measurement device to a pressure tap in the affected facility's vapor collection system, located as close as possible to the connection with the tank truck or railcar.

(3) During the performance test, record the pressure every 5 minutes while a tank truck or railcar is being loaded, and record the highest instantaneous pressure that occurs during each loading cycle. Every loading rack shall be tested at least once during the performance test.

(4) If more than one loading rack is used simultaneously, then the performance test shall be conducted simultaneously to represent the maximum capacity.

(d) For the purpose of determining compliance with §61.302(j), the following procedures shall be used:

(1) Calibrate and install a pressure measurement device (liquid manometer, magnehelic gauge, or equivalent instrument), capable of measuring up to the relief set pressure of the pressure-vacuum vents.

(2) Connect the pressure measurement device to a pressure tap in the affected facility's vapor collection system, located as close as possible to the connection with the marine vessel.

(3) During the performance test, record the pressure every 5 minutes while a marine vessel is being loaded, and record the highest instantaneous pressure that occurs during each loading cycle.

(e) Immediately prior to a performance test required for determination of compliance with §61.302(b), all potential sources of vapor leakage in the affected facility's vapor collection system equipment shall be inspected for detectable emissions as required in §61.302(k). The monitoring shall be conducted only while a vapor-tight tank truck, railcar, or marine vessel is being loaded. All identified leaks in the terminal's vapor collection system shall be repaired prior to conducting the performance test.

(f) The following test method shall be used to comply with the marine vessel vapor-tightness requirements of §61.302(e)(3):

(1) Each benzene product tank shall be pressurized with dry air or inert gas to not less than 1.0 psig and not more than the pressure of the lowest relief valve setting.

(2) Once the pressure is obtained, the dry air or inert gas source shall be shut off.

(3) At the end of one-half hour, the pressure in the benzene product tank and piping shall be measured. The change in pressure shall be calculated using the following formula:

$\Delta P = P_i — P_f$

where:

ΔP = Change in pressure, inches of water.

P_i = Pressure in tank when air/gas source is shut off, inches of water.

P_f = Pressure in tank at the end of one-half hour after air/gas source is shut off, inches of water.

(4) The change in pressure, ΔP, shall be compared to the pressure drop calculated using the following formula:

$\Delta PM = 0.861 P_{ia} L/V$

where:

ΔPM = Maximum allowable pressure change, inches of water.

P_{ia} = Pressure in tank when air/gas source is shut off, pounds per square inch, absolute (psia).

L = Maximum permitted loading rate of vessel, barrels per hour.

V = Total volume of product tank, barrels.

(5) If $\Delta P \leq \Delta PM$, the vessel is vapor tight.

(6) If $\Delta P > \Delta PM$, the vessel is not vapor tight and the source of the leak must be identified and repaired prior to retesting.

[55 FR 8341, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 65 FR 62159, Oct. 17, 2000]

§61.305 Reporting and recordkeeping.

(a) Each owner or operator of an affected facility subject to the provisions of this subpart shall keep an up-to-date, readily accessible record of the following data measured during each performance test, and also include the following data in the report of the initial performance test required under §61.13. Where a steam generating unit or process heater with a design heat input capacity of 44 MW (150×10^6 BTU/hr) or greater is used to comply with §61.302(b), a report containing performance test data need not be submitted, but a report containing the information in §61.305(a)(3)(i) is required.

(1) Where an owner or operator subject to the provisions of this subpart is complying with §61.302(b) through use of an incinerator:

(i) The average firebox temperature of the incinerator (or the average temperature upstream and downstream of the catalyst bed), measured at least every 2 minutes during a loading cycle if the total time period of the loading cycle is less than 3 hours and every 15 minutes if the total time period of the loading cycle is equal to or greater than 3 hours. The measured temperature shall be averaged over the loading cycle.

(ii) The percent reduction of benzene determined as specified in §61.304(a) achieved by the incinerator.

(iii) The duration of the loading cycle.

(2) Where an owner or operator subject to the provisions of this subpart is complying with §61.302 (b) and (c) through use of a smokeless flare or other flare design (i.e., steam-assisted, air-assisted or nonassisted), all visible emission readings, heat content determination, flow rate measurements, maximum permitted velocity calculations, and exit velocity determinations made during the performance test, continuous records of the flare pilot flame monitoring measured continuously during the loading cycle, duration of all loading cycles and records of all loading cycles during which the pilot flame is absent for each vent stream.

(3) Where an owner or operator subject to the provisions of this subpart is complying with §61.302(b) through the use of a steam generating unit or process heater:

(i) A description of the location at which the vent stream is introduced into the steam generating unit or process heater.

(ii) The average combustion temperature of the steam generating unit or process heater with a design heat input capacity of less than 44 MW (150×10^6 BTU/hr), measured with the following frequency: at least every 2 minutes during a loading cycle if the total time period of the loading cycle is less than 3 hours, and every 15 minutes if the total time period of the loading cycle is equal to or greater than 3 hours. The measured temperature shall be averaged over the loading cycle.

(iii) The duration of the loading cycle.

(4) Where an owner or operator subject to the provisions of this subpart is complying with §61.302(b) through the use of a carbon adsorption system, the control efficiency, R, of the carbon adsorption system, and all supporting performance test data and calculations used to determine that value.

(5) Each owner or operator subject to the provisions of this subpart shall submit with the initial performance test an engineering report describing in detail the vent system used to vent each affected vent stream to a control device. This report shall include all valves and vent pipes that could vent the stream to the atmosphere, thereby bypassing the control device, and identify which valves are car-sealed opened and which valves are car-sealed closed.

(b) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §61.303 (a), (c), and (d) as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) For thermal incinerators, all loading cycles during which the average combustion temperature was more than 28 °C (50 °F) below the average loading cycle combustion temperature during the most recent performance test at which compliance with §61.302(b) was determined.

(2) For catalytic incinerators, all loading cycles during which the average temperature of the vent stream immediately before the catalyst bed is more than 28 °C (50 °F) below the average temperature of the process vent stream during loading cycles during the most recent performance test at which compliance with §61.302(b) was determined.

(3) All loading cycles during which the average combustion temperature was more than 28 °C (50 °F) below the average combustion temperature during the most recent performance test at which compliance with §61.302(b) was determined for steam generating units or process heaters with a design heat input capacity of less than 44 MW (150 × 10^6 BTU/hr).

(4) For steam generating units or process heaters, whenever there is a change in the location at which the vent stream is introduced into the flame zone as required under §61.302(b).

(5) For carbon adsorbers, all 3-hour periods of operation during which the average VOC concentration or reading of organics in the exhaust gases is more than 20 percent greater than the average exhaust gas concentration or reading measured by the organics monitoring device during the most recent determination of the recovery efficiency of the carbon adsorber that demonstrated that the facility was in compliance.

(c) If a vent system containing valves that could divert the emission stream away from the control device is used, each owner or operator subject to the provisions of this subpart shall keep for at least 2 years up-to-date, readily accessible continuous records of:

(1) All periods when flow is indicated if flow indicators are installed under §61.303(g)(1).

(2) All times when maintenance is performed on car-sealed valves, when the car seal is broken, and when the valve position is changed (i.e., from open to closed for valves in the vent piping to the control device and from closed to open for valves that vent the stream directly or indirectly to the atmosphere bypassing the control device) if valves are monitored under §60.303(g)(2).

(d) Each owner or operator of an affected facility subject to the provisions of this subpart who uses a steam generating unit or process heater with a design heat input capacity of 44 MW (150 × 10^6 BTU/hr) or greater to comply with §61.302(b) shall keep an up-to-date, readily accessible record of all periods of operation of the steam generating unit or process heater. Examples of such records could include records of steam use, fuel use, or monitoring data collected pursuant to other State or Federal regulatory requirements.

(e) Each owner or operator of an affected facility subject to the provisions of this subpart shall keep up-to-date, readily accessible records of the flare pilot flame monitoring specified under §61.303(b), as well as up-to-date, readily accessible records of any absence of the pilot flame during a loading cycle.

(f) Each owner or operator of an affected facility subject to the requirements of §61.302 shall submit to the Administrator quarterly reports of the following information. The owner or operator shall submit the initial report within 90 days after the effective date of this subpart or 90 days after startup for a source that has an initial startup date after the effective date.

(1) Periods of operation where there were exceedances of monitored parameters recorded under §61.305(b).

(2) All periods recorded under §61.305(c)(1) when the vent stream is diverted from the control device.

(3) All periods recorded under §61.305(d) when the steam generating unit or process heater was not operating.

(4) All periods recorded under §61.305(e) in which the pilot flame of the flare was absent.

(5) All times recorded under §61.305(c)(2) when maintenance is performed on car-sealed valves, when the car seal is broken, and when the valve position is changed.

(g) The owner or operator of an affected facility shall keep the vapor-tightness documentation required under §61.302 (d) and (e) on file at the affected facility in a permanent form available for inspection.

(h) The owner or operator of an affected facility shall update the documentation file required under §61.302 (d) and (e) for each tank truck, railcar, or marine vessel at least once per year to reflect current test results as determined by the appropriate method. The owner or operator shall include, as a minimum, the following information in this documentation:

(1) Test title;

(2) Tank truck, railcar, or marine vessel owner and address;

(3) Tank truck, railcar, or marine vessel identification number;

(4) Testing location;

(5) Date of test;

(6) Tester name and signature;

(7) Witnessing inspector: name, signature, and affiliation; and

(8) Test results, including, for railcars and tank trucks, the initial pressure up to which the tank was pressured at the start of the test.

(i) Each owner or operator of an affected facility complying with §61.300(b) or §61.300(d) shall record the following information. The first year after promulgation the owner or operator shall submit a report containing the requested information to the Director of the Emission Standards Division, (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711. After the first year, the owner or operator shall continue to record; however, no reporting is required. The information shall be made available if requested. The information shall include, as a minimum:

(1) The affected facility's name and address;

(2) The weight percent of the benzene loaded;

(3) The type of vessel loaded (i.e., tank truck, railcar, or marine vessel); and

(4) The annual amount of benzene loaded into each type of vessel.

[55 FR 8341, Mar. 7, 1990, as amended at 65 FR 62159, Oct. 17, 2000]

§61.306 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(d) 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: No restrictions.

Attachment M

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on May 21, 2013]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Subpart FF—National Emission Standard for Benzene Waste Operations

Source: 55 FR 8346, Mar. 7, 1990, unless otherwise noted.

§ 61.340 Applicability.

(a) The provisions of this subpart apply to owners and operators of chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries.

(b) The provisions of this subpart apply to owners and operators of hazardous waste treatment, storage, and disposal facilities that treat, store, or dispose of hazardous waste generated by any facility listed in paragraph (a) of this section. The waste streams at hazardous waste treatment, storage, and disposal facilities subject to the provisions of this subpart are the benzene-containing hazardous waste from any facility listed in paragraph (a) of this section. A hazardous waste treatment, storage, and disposal facility is a facility that must obtain a hazardous waste management permit under subtitle C of the Solid Waste Disposal Act.

(c) At each facility identified in paragraph (a) or (b) of this section, the following waste is exempt from the requirements of this subpart:

(1) Waste in the form of gases or vapors that is emitted from process fluids:

(2) Waste that is contained in a segregated stormwater sewer system.

(d) At each facility identified in paragraph (a) or (b) of this section, any gaseous stream from a waste management unit, treatment process, or wastewater treatment system routed to a fuel gas system, as defined in § 61.341, is exempt from this subpart. No testing, monitoring, recordkeeping, or reporting is required under this subpart for any gaseous stream from a waste management unit, treatment process, or wastewater treatment unit routed to a fuel gas system.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

§ 61.341 Definitions.

Benzene concentration means the fraction by weight of benzene in a waste as determined in accordance with the procedures specified in § 61.355 of this subpart.

Car-seal means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Chemical manufacturing plant means any facility engaged in the production of chemicals by chemical, thermal, physical, or biological processes for use as a product, co-product, by-product, or intermediate including but not limited to industrial organic chemicals, organic pesticide products, pharmaceutical preparations, paint and allied products, fertilizers, and agricultural chemicals. Examples of chemical manufacturing plants include facilities at which process units are operated to produce one or more of the following chemicals: benzenesulfonic acid, benzene, chlorobenzene, cumene, cyclohexane, ethylene, ethylbenzene, hydroquinone, linear alklylbenzene, nitrobenzene, resorcinol, sulfolane, or styrene.

Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission source to a control device.

Coke by-product recovery plant means any facility designed and operated for the separation and recovery of coal tar derivatives (by-products) evolved from coal during the coking process of a coke oven battery.

Container means any portable waste management unit in which a material is stored, transported, treated, or otherwise handled. Examples of containers are drums, barrels, tank trucks, barges, dumpsters, tank cars, dump trucks, and ships.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Cover means a device or system which is placed on or over a waste placed in a waste management unit so that the entire waste surface area is enclosed and sealed to minimize air emissions. A cover may have openings necessary for operation, inspection, and maintenance of the waste management unit such as access hatches, sampling ports, and gauge wells provided that each opening is closed and sealed when not in use. Example of covers include a fixed roof installed on a tank, a lid installed on a container, and an air-supported enclosure installed over a waste management unit.

External floating roof means a pontoon-type or double-deck type cover with certain rim sealing mechanisms that rests on the liquid surface in a waste management unit with no fixed roof.

Facility means all process units and product tanks that generate waste within a stationary source, and all waste management units that are used for waste treatment, storage, or disposal within a stationary source.

Fixed roof means a cover that is mounted on a waste management unit in a stationary manner and that does not move with fluctuations in liquid level.

Floating roof means a cover with certain rim sealing mechanisms consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and unit wall.

Flow indicator means a device which indicates whether gas flow is present in a line or vent system.

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous streams generated by facility operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside the facility. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric.

Individual drain system means the system used to convey waste from a process unit, product storage tank, or waste management unit to a waste management unit. The term includes all process drains and common junction boxes, together with their associated sewer lines and other junction boxes, down to the receiving waste management unit.

Internal floating roof means a cover that rests or floats on the liquid surface inside a waste management unit that has a fixed roof.

Liquid-mounted seal means a foam or liquid-filled primary seal mounted in contact with the liquid between the waste management unit wall and the floating roof continuously around the circumference.

Loading means the introduction of waste into a waste management unit but not necessarily to complete capacity (also referred to as filling).

Maximum organic vapor pressure means the equilibrium partial pressure exerted by the waste at the temperature equal to the highest calendar-month average of the waste storage temperature for waste stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for waste stored at the ambient temperature, as determined:

(1) In accordance with § 60.17(c); or

(2) As obtained from standard reference texts; or

(3) In accordance with § 60.17(a)(37); or

(4) Any other method approved by the Administrator.

No detectable emissions means less than 500 parts per million by volume (ppmv) above background levels, as measured by a detection instrument reading in accordance with the procedures specified in § 61.355(h) of this subpart.

Oil-water separator means a waste management unit, generally a tank or surface impoundment, used to separate oil from water. An oil-water separator consists of not only the separation unit but also the forebay and other separator basins, skimmers, weirs, grit chambers, sludge hoppers, and bar screens that are located directly after the individual drain system and prior to additional treatment units such as an air flotation unit, clarifier, or biological treatment unit. Examples of an oil-water separator incude an API separator, parallel-plate interceptor, and corrugated-plate interceptor with the associated ancillary equipment.

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

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

Point of waste generation means the location where the waste stream exits the process unit component or storage tank prior to handling or treatment in an operation that is not an integral part of the production process, or in the case of waste management units that generate new wastes after treatment, the location where the waste stream exits the waste management unit component.

Process unit means equipment assembled and connected by pipes or ducts to produce intermediate or final products. A process unit can be operated independently if supplied with sufficient fuel or raw materials and sufficient product storage facilities.

Process unit turnaround means the shutting down of the operations of a process unit, the purging of the contents of the process unit, the maintenance or repair work, followed by restarting of the process.

Process unit turnaround waste means a waste that is generated as a result of a process unit turnaround.

Process wastewater means water which comes in contact with benzene during manufacturing or processing operations conducted within a process unit. Process wastewater is not organic wastes, process fluids, product tank drawdown, cooling tower blowdown, steam trap condensate, or landfill leachate.

Process wastewater stream means a waste stream that contains only process wastewater.

Product tank means a stationary unit that is designed to contain an accumulation of materials that are fed to or produced by a process unit, and is constructed primarily of non-earthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

Product tank drawdown means any material or mixture of materials discharged from a product tank for the purpose of removing water or other contaminants from the product tank.

Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event. For the purpose of this subpart, a safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in this vapor headspace in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the air emission control equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes, standard engineering codes and practices, or other requirements for the safe handling of flammable, ignitable, explosive, reactive, or hazardous materials.

Segregated stormwater sewer system means a drain and collection system designed and operated for the sole purpose of collecting rainfall runoff at a facility, and which is segregated from all other individual drain systems.

Sewer line means a lateral, trunk line, branch line, or other enclosed conduit used to convey waste to a downstream waste management unit.

Slop oil means the floating oil and solids that accumulate on the surface of an oil-water separator.

Sour water stream means a stream that:

(1) Contains ammonia or sulfur compounds (usually hydrogen sulfide) at concentrations of 10 ppm by weight or more;

(2) Is generated from separation of water from a feed stock, intermediate, or product that contained ammonia or sulfur compounds; and

(3) Requires treatment to remove the ammonia or sulfur compounds.

Sour water stripper means a unit that:

(1) Is designed and operated to remove ammonia or sulfur compounds (usually hydrogen sulfide) from sour water streams;

(2) Has the sour water streams transferred to the stripper through hard piping or other enclosed system; and

(3) Is operated in such a manner that the offgases are sent to a sulfur recovery unit, processing unit, incinerator, flare, or other combustion device.

Surface impoundment means a waste management unit which is a natural topographic depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to hold an accumulation of liquid wastes or waste containing free liquids, and which is not an injection well. Examples of surface impoundments are holding, storage, settling, and aeration pits, ponds, and lagoons.

Tank means a stationary waste management unit that is designed to contain an accumulation of waste and is constructed primarily of nonearthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

Treatment process means a stream stripping unit, thin-film evaporation unit, waste incinerator, or any other process used to comply with § 61.348 of this subpart.

Vapor-mounted seal means a foam-filled primary seal mounted continuously around the perimeter of a waste management unit so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the unit wall, the liquid surface, and the floating roof.

Waste means any material resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, thermally, or biologically treated prior to being discarded, recycled, or discharged.

Waste management unit means a piece of equipment, structure, or transport mechanism used in handling, storage, treatment, or disposal of waste. Examples of a waste management unit include a tank, surface impoundment, container, oil-water separator, individual drain system, steam stripping unit, thin-film evaporation unit, waste incinerator, and landfill.

Waste stream means the waste generated by a particular process unit, product tank, or waste management unit. The characteristics of the waste stream (e.g., flow rate, benzene concentration, water content) are determined at the point of waste generation. Examples of a waste stream include process wastewater, product tank drawdown, sludge and slop oil removed from waste management units, and landfill leachate.

Wastewater treatment system means any component, piece of equipment, or installation that receives, manages, or treats process wastewater, product tank drawdown, or landfill leachate prior to direct or indirect discharge in accordance with the National Pollutant Discharge Elimination System permit regulations under 40 CFR part 122. These systems typically include individual drain systems, oil-water separators, air flotation units, equalization tanks, and biological treatment units.

Water seal controls means a seal pot, p-leg trap, or other type of trap filled with water (e.g., flooded sewers that maintain water levels adequate to prevent air flow through the system) that creates a water barrier between the sewer line and the atmosphere. The water level of the seal must be maintained in the vertical leg of a drain in order to be considered a water seal.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

§ 61.342 Standards: General.

(a) An owner or operator of a facility at which the total annual benzene quantity from facility waste is less than 10 megagrams per year (Mg/yr) (11 ton/yr) shall be exempt from the requirements of paragraphs (b) and (c) of this section. The total annual benzene quantity from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent. The benzene quantity in a waste stream is to be counted only once without multiple counting if other waste streams are mixed with or generated from the original waste stream. Other specific requirements for calculating the total annual benzene waste quantity are as follows:

(1) Wastes that are exempted from control under §§ 61.342(c)(2) and 61.342(c)(3) are included in the calculation of the total annual benzene quantity if they have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(2) The benzene in a material subject to this subpart that is sold is included in the calculation of the total annual benzene quantity if the material has an annual average water content greater than 10 percent.

(3) Benzene in wastes generated by remediation activities conducted at the facility, such as the excavation of contaminated soil, pumping and treatment of groundwater, and the recovery of product from soil or groundwater, are not included in the calculation of total annual benzene quantity for that facility. If the facility's total annual benzene quantity is 10 Mg/yr (11 ton/yr) or more, wastes generated by remediation activities are subject to the requirements of paragraphs (c) through (h) of this section. If the facility is managing remediation waste generated offsite, the benzene in this waste shall be included in the calculation of total annual benzene quantity in facility waste, if the waste streams

have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(4) The total annual benzene quantity is determined based upon the quantity of benzene in the waste before any waste treatment occurs to remove the benzene except as specified in § 61.355(c)(1)(i) (A) through (C).

(b) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall be in compliance with the requirements of paragraphs (c) through (h) of this section no later than 90 days following the effective date, unless a waiver of compliance has been obtained under § 61.11, or by the initial startup for a new source with an initial startup after the effective date.

(1) The owner or operator of an existing source unable to comply with the rule within the required time may request a waiver of compliance under § 61.10.

(2) As part of the waiver application, the owner or operator shall submit to the Administrator a plan under § 61.10(b)(3) that is an enforceable commitment to obtain environmental benefits to mitigate the benzene emissions that result from extending the compliance date. The plan shall include the following information:

(i) A description of the method of compliance, including the control approach, schedule for installing controls, and quantity of the benzene emissions that result from extending the compliance date;

(ii) If the control approach involves a compliance strategy designed to obtain integrated compliance with multiple regulatory requirements, a description of the other regulations involved and their effective dates; and

(iii) A description of the actions to be taken at the facility to obtain mitigating environmental benefits, including how the benefits will be obtained, the schedule for these actions, and an estimate of the quantifiable benefits that directly result from these actions.

(c) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall manage and treat the facility waste as follows:

(1) For each waste stream that contains benzene, including (but not limited to) organic waste streams that contain less than 10 percent water and aqueous waste streams, even if the wastes are not discharged to an individual drain system, the owner or operator shall:

(i) Remove or destroy the benzene contained in the waste using a treatment process or wastewater treatment system that complies with the standards specified in § 61.348 of this subpart.

(ii) Comply with the standards specified in §§ 61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste stream prior to and during treatment of the waste stream in accordance with paragraph (c)(1)(i) of this section.

(iii) Each waste management unit used to manage or treat waste streams that will be recycled to a process shall comply with the standards specified in §§ 61.343 through 61.347. Once the waste stream is recycled to a process, including to a tank used for the storage of production process feed, product, or product intermediates, unless this tank is used primarily for the storage of wastes, the material is no longer subject to paragraph (c) of this section.

(2) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the flow-weighted annual average benzene concentration for the waste stream is less than 10 ppmw as determined by the procedures specified in § 61.355(c)(2) or § 61.355(c)(3).

(3) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the conditions specified in either paragraph (c)(3)(i) or (c)(3)(ii) of this section are met.

(i) The waste stream is process wastewater that has a flow rate less than 0.02 liters per minute (0.005 gallons per minute) or an annual wastewater quantity of less than 10 Mg/yr (11 ton/yr); or

(ii) All of the following conditions are met:

(A) The owner or operator does not choose to exempt process wastewater under paragraph (c)(3)(i) of this section,

(B) The total annual benzene quantity in all waste streams chosen for exemption in paragraph (c)(3)(ii) of this section does not exceed 2.0 Mg/yr (2.2 ton/yr) as determined in the procedures in § 61.355(j), and

(C) The total annual benzene quantity in a waste stream chosen for exemption, including process unit turnaround waste, is determined for the year in which the waste is generated.

(d) As an alternative to the requirements specified in paragraphs (c) and (e) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste other than process wastewater in accordance with the requirements of paragraph (c)(1) of this section.

(2) The owner or operator shall manage and treat process wastewater in accordance with the following requirements:

(i) Process wastewater shall be treated to achieve a total annual benzene quantity from facility process wastewater less than 1 Mg/yr (1.1 ton/yr). Total annual benzene from facility process wastewater shall be determined by adding together the annual benzene quantity at the point of waste generation for each untreated process wastewater stream plus the annual benzene quantity exiting the treatment process for each process wastewater stream treated in accordance with the requirements of paragraph (c)(1)(i) of this section.

(ii) Each treated process wastewater stream identified in paragraph (d)(2)(i) of this section shall be managed and treated in accordance with paragraph (c)(1) of this section.

(iii) Each untreated process wastewater stream identified in paragraph (d)(2)(i) of this section is exempt from the requirements of paragraph (c)(1) of this section.

(e) As an alternative to the requirements specified in paragraphs (c) and (d) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste with a flow-weighted annual average water content of less than 10 percent in accordance with the requirements of paragraph (c)(1) of this section; and

(2) The owner or operator shall manage and treat facility waste (including remediation and process unit turnaround waste) with a flow-weighted annual average water content of 10 percent or greater, on a volume basis as total water, and each waste stream that is mixed with water or wastes at any time such that the resulting mixture has an annual water content greater than 10 percent, in accordance with the following:

(i) The benzene quantity for the wastes described in paragraph (e)(2) of this section must be equal to or less than 6.0 Mg/yr (6.6 ton/yr), as determined in § 61.355(k). Wastes as described in paragraph (e)(2) of this section that are transferred offsite shall be included in the determination of benzene quantity as provided in § 61.355(k). The provisions of paragraph (f) of this section shall not apply to any owner or operator who elects to comply with the provisions of paragraph (e) of this section.

(ii) The determination of benzene quantity for each waste stream defined in paragraph (e)(2) of this section shall be made in accordance with § 61.355(k).

(f) Rather than treating the waste onsite, an owner or operator may elect to comply with paragraph (c)(1)(i) of this section by transferring the waste offsite to another facility where the waste is treated in accordance with the requirements of paragraph (c)(1)(i) of this section. The owner or operator transferring the waste shall:

(1) Comply with the standards specified in §§ 61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste prior to shipment of the waste offsite.

(2) Include with each offsite waste shipment a notice stating that the waste contains benzene which is required to be managed and treated in accordance with the provisions of this subpart.

(g) Compliance with this subpart will be determined by review of facility records and results from tests and inspections using methods and procedures specified in § 61.355 of this subpart.

(h) Permission to use an alternative means of compliance to meet the requirements of §§ 61.342 through 61.352 of this subpart may be granted by the Administrator as provided in § 61.353 of this subpart.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 65 FR 62159, 62160, Oct. 17, 2000]

§ 61.343   Standards: Tanks.

(a) Except as provided in paragraph (b) of this section and in § 61.351, the owner or operator must meet the standards in paragraph (a)(1) or (2) of this section for each tank in which the waste stream is placed in accordance with § 61.342 (c)(1)(ii). The standards in this section apply to the treatment and storage of the waste stream in a tank, including dewatering.

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the tank to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the tank except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the tank is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of thefollowing conditions:

(*1*) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(*2*) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(*3*) The pressure is monitored continuously to ensure that the pressure in the tank remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of § 61.349 of this subpart.

(2) The owner or operator must install, operate, and maintain an enclosure and closed-vent system that routes all organic vapors vented from the tank, located inside the enclosure, to a control device in accordance with the requirements specified in paragraph (e) of this section.

(b) For a tank that meets all the conditions specified in paragraph (b)(1) of this section, the owner or operator may elect to comply with paragraph (b)(2) of this section as an alternative to the requirements specified in paragraph (a)(1) of this section.

(1) The waste managed in the tank complying with paragraph (b)(2) of this section shall meet all of the following conditions:

(i) Each waste stream managed in the tank must have a flow-weighted annual average water content less than or equal to 10 percent water, on a volume basis as total water.

(ii) The waste managed in the tank either:

(A) Has a maximum organic vapor pressure less than 5.2 kilopascals (kPa) (0.75 pounds per square inch (psi));

(B) Has a maximum organic vapor pressure less than 27.6 kPa (4.0 psi) and is managed in a tank having design capacity less than 151 m^3 (40,000 gal); or

(C) Has a maximum organic vapor pressure less than 76.6 kPa (11.1 psi) and is managed in a tank having a design capacity less than 75 m^3 (20,000 gal).

(2) The owner or operator shall install, operate, and maintain a fixed roof as specified in paragraph (a)(1)(i).

(3) For each tank complying with paragraph (b) of this section, one or more devices which vent directly to the atmosphere may be used on the tank provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the tank or cover resulting from filling or emptying the tank, diurnal temperature changes, atmospheric pressure changes or malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(c) Each fixed-roof, seal, access door, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access doors and other openings are closed and gasketed properly.

(d) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 45 calendar days after identification.

(e) Each owner or operator who controls air pollutant emissions by using an enclosure vented through a closed-vent system to a control device must meet the requirements specified in paragraphs (e)(1) through (4) of this section.

(1) The tank must be located inside a total enclosure. The enclosure must be designed and operated in accordance with the criteria for a permanent total enclosure as specified in “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of material into or out of the enclosure by conveyor, vehicles, or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of Procedure T initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the requirements for Tank Level 2 control requirements 40 CFR 264.1084(i) or 40 CFR 265(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(2) The enclosure must be vented through a closed-vent system to a control device that is designed and operated in accordance with the standards for control devices specified in § 61.349.

(3) Safety devices, as defined in this subpart, may be installed and operated as necessary on any enclosure, closed-vent system, or control device used to comply with the requirements of paragraphs (e)(1) and (2) of this section.

(4) The closed-vent system must be designed and operated in accordance with the requirements of § 61.349.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 18331, May 2, 1990; 58 FR 3096, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 6082, Feb. 6, 2003; 68 FR 67935, Dec. 4, 2003]

§ 61.344 Standards: Surface impoundments.

(a) The owner or operator shall meet the following standards for each surface impoundment in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each surface impoundment a cover (e.g., air-supported structure or rigid cover) and closed-vent system that routes all organic vapors vented from the surface impoundment to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the surface impoundment except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the enclosure of the surface impoundment is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(*1*) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(*2*) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart; and

(*3*) The pressure is monitored continuously to ensure that the pressure in the enclosure of the surface impoundment remains below atmospheric pressure.

(D) The cover shall be used at all times that waste is placed in the surface impoundment except during removal of treatment residuals in accordance with 40 CFR 268.4 or closure of the surface impoundment in accordance with 40 CFR 264.228. (Note: the treatment residuals generated by these activities may be subject to the requirements of this part.)

(ii) The closed-vent system and control device shall be designed and operated in accordance with § 61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993]

§ 61.345 Standards: Containers.

(a) The owner or operator shall meet the following standards for each container in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a cover on each container used to handle, transfer, or store waste in accordance with the following requirements:

(i) The cover and all openings (e.g., bungs, hatches, and sampling ports) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(ii) Except as provided in paragraph (a)(4) of this section, each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the container except when it is necessary to use the opening for waste loading, removal, inspection, or sampling.

(2) When a waste is transferred into a container by pumping, the owner or operator shall perform the transfer using a submerged fill pipe. The submerged fill pipe outlet shall extend to within two fill pipe diameters of the bottom of the container while the container is being loaded. During loading of the waste, the cover shall remain in place and all openings shall be maintained in a closed, sealed position except for those openings required for the submerged fill pipe, those openings required for venting of the container to prevent physical damage or permanent deformation of the container or cover, and any openings complying with paragraph (a)(4) of this section.

(3) Treatment of a waste in a container, including aeration, thermal or other treatment, must be performed by the owner or operator in a manner such that while the waste is being treated the container meets the standards specified in paragraphs (a)(3)(i) through (iii) of this section, except for covers and closed-vent systems that meet the requirements in paragraph (a)(4) of this section.

(i) The owner or operator must either:

(A) Vent the container inside a total enclosure which is exhausted through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(A) and (B) of this section; or

(B) Vent the covered or closed container directly through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(B) and (C) of this section.

(ii) The owner or operator must meet the following requirements, as applicable to the type of air emission control equipment selected by the owner or operator:

(A) The total enclosure must be designed and operated in accordance with the criteria for a permanent total enclosure as specified in section 5 of the "Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure" in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of containers through the enclosure by conveyor or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of "Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure" initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the Container Level 3 control requirements in 40 CFR 264.1086(e)(2)(i) or 40 CFR 265.1086(e)(2)(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(B) The closed-vent system and control device must be designed and operated in accordance with the requirements of § 61.349.

(C) For a container cover, the cover and all openings (*e.g.,* doors, hatches) must be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h).

(iii) Safety devices, as defined in this subpart, may be installed and operated as necessary on any container, enclosure, closed-vent system, or control device used to comply with the requirements of paragraph (a)(3)(i) of this section.

(4) If the cover and closed-vent system operate such that the container is maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by methods specified in § 61.355(h); and

(iii) The pressure is monitored continuously to ensure that the pressure in the container remains below atmospheric pressure.

(b) Each cover and all openings shall be visually inspected initially and quarterly thereafter to ensure that they are closed and gasketed properly.

(c) Except as provided in § 61.350 of this subpart, 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 identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 67936, Dec. 4, 2003]

§ 61.346 Standards: Individual drain systems.

(a) Except as provided in paragraph (b) of this section, the owner or operator shall meet the following standards for each individual drain system in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each drain system opening a cover and closed-vent system that routes all organic vapors vented from the drain system to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports) shall be designed to operate with no detactable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the drain system except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the individual drain system is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(*1*) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(*2*) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(*3*) The pressure is monitored continuously to ensure that the pressure in the individual drain system remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with § 61.349 of this subpart.

(2) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(3) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

(b) As an alternative to complying with paragraph (a) of this section, an owner or operator may elect to comply with the following requirements:

(1) Each drain shall be equipped with water seal controls or a tightly sealed cap or plug.

(2) Each junction box shall be equipped with a cover and may have a 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.

(i) 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.

(ii) One of the following methods shall be used to control emissions from the junction box vent pipe to the atmosphere:

(A) Equip the junction box with a system to prevent the flow of organic vapors from the junction box vent pipe to the atmosphere during normal operation. An example of such a system includes use of water seal controls on the junction box. A flow indicator shall be installed, operated, and maintained on each junction box vent pipe to ensure that organic vapors are not vented from the junction box to the atmosphere during normal operation.

(B) Connect the junction box vent pipe to a closed-vent system and control device in accordance with § 61.349 of this subpart.

(3) Each sewer line 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.

(4) Equipment installed in accordance with paragraphs (b)(1), (b)(2), or (b)(3) of this section shall be inspected as follows:

(i) Each drain using water seal controls shall be checked by visual or physical inspection initially and thereafter quarterly for indications of low water levels or other conditions that would reduce the effectiveness of water seal controls.

(ii) Each drain using a tightly sealed cap or plug shall be visually inspected initially and thereafter quarterly to ensure caps or plugs are in place and properly installed.

(iii) Each junction box shall be visually inspected initially and thereafter quarterly to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(iv) The unburied portion of each sewer line shall be visually inspected initially and thereafter quarterly for indication of cracks, gaps, or other problems that could result in benzene emissions.

(5) Except as provided in § 61.350 of this subpart, when a broken seal, gap, crack or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3097, Jan. 7, 1993]

§ 61.347 Standards: Oil-water separators.

(a) Except as provided in § 61.352 of this subpart, the owner or operator shall meet the following standards for each oil-water separator in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the oil-water separator to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the oil-water separator except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the oil-water separator is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

(*1*) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(*2*) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(*3*) The pressure is monitored continuously to ensure that the pressure in the oil-water separator remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of § 61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur between the cover and oil-water separator wall and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3098, Jan. 7, 1993]

§ 61.348 Standards: Treatment processes.

(a) Except as provided in paragraph (a)(5) of this section, the owner or operator shall treat the waste stream in accordance with the following requirements:

(1) The owner or operator shall design, install, operate, and maintain a treatment process that either:

(i) Removes benzene from the waste stream to a level less than 10 parts per million by weight (ppmw) on a flow-weighted annual average basis,

(ii) Removes benzene from the waste stream by 99 percent or more on a mass basis, or

(iii) Destroys benzene in the waste stream by incinerating the waste in a combustion unit that achieves a destruction efficiency of 99 percent or greater for benzene.

(2) Each treatment process complying with paragraphs (a)(1)(i) or (a)(1)(ii) of this section shall be designed and operated in accordance with the appropriate waste management unit standards specified in §§ 61.343 through 61.347 of this subpart. For example, if a treatment process is a tank, then the owner or operator shall comply with § 61.343 of this subpart.

(3) For the purpose of complying with the requirements specified in paragraph (a)(1)(i) of this section, the intentional or unintentional reduction in the benzene concentration of a waste stream by dilution of the waste stream with other wastes or materials is not allowed.

(4) An owner or operator may aggregate or mix together individual waste streams to create a combined waste stream for the purpose of facilitating treatment of waste to comply with the requirements of paragraph (a)(1) of this section except as provided in paragraph (a)(5) of this section.

(5) If an owner or operator aggregates or mixes any combination of process wastewater, product tank drawdown, or landfill leachate subject to § 61.342(c)(1) of this subpart together with other waste streams to create a combined waste stream for the purpose of facilitating management or treatment of waste in a wastewater treatment system, then the wastewater treatment system shall be operated in accordance with paragraph (b) of this section. These provisions apply to above-ground wastewater treatment systems as well as those that are at or below ground level.

(b) Except for facilities complying with § 61.342(e), the owner or operator that aggregates or mixes individual waste streams as defined in paragraph (a)(5) of this section for management and treatment in a wastewater treatment system shall comply with the following requirements:

(1) The owner or operator shall design and operate each waste management unit that comprises the wastewater treatment system in accordance with the appropriate standards specified in §§ 61.343 through 61.347 of this subpart.

(2) The provisions of paragraph (b)(1) of this section do not apply to any waste management unit that the owner or operator demonstrates to meet the following conditions initially and, thereafter, at least once per year:

(i) The benzene content of each waste stream entering the waste management unit is less than 10 ppmw on a flow-weighted annual average basis as determined by the procedures specified in § 61.355(c) of this subpart; and

(ii) The total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units comprising the facility wastewater treatment systems is less than 1 Mg/yr (1.1 ton/yr). For this determination, total annual benzene quantity shall be calculated as follows:

(A) The total annual benzene quantity shall be calculated as the sum of the individual benzene quantities determined at each location where a waste stream first enters an exempt waste management unit. The benzene quantity discharged from an exempt waste management unit shall not be included in this calculation.

(B) The annual benzene quantity in a waste stream managed or treated in an enhanced biodegradation unit shall not be included in the calculation of the total annual benzene quantity, if the enhanced biodegradation unit is the first exempt unit in which the waste is managed or treated. A unit shall be considered enhanced biodegradation if it is a suspended-growth process that generates biomass, uses recycled biomass, and periodically removes biomass from the process. An enhanced biodegradation unit typically operates at a food-to-microorganism ratio in the range of 0.05 to 1.0 kg of biological oxygen demand per kg of biomass per day, a mixed liquor suspended solids ratio in the range of 1 to 8 grams per liter (0.008 to 0.7 pounds per liter), and a residence time in the range of 3 to 36 hours.

(c) The owner and operator shall demonstrate that each treatment process or wastewater treatment system unit, except as provided in paragraph (d) of this section, achieves the appropriate conditions specified in paragraphs (a) or (b) of this section in accordance with the following requirements:

(1) Engineering calculations in accordance with requirements specified in § 61.356(e) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in § 61.355 of this subpart.

(d) A treatment process or waste stream is in compliance with the requirements of this subpart and exempt from the requirements of paragraph (c) of this section provided that the owner or operator documents that the treatment process or waste stream is in compliance with other regulatory requirements as follows:

(1) The treatment process is a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O;

(2) The treatment process is an industrial furnace or boiler burning hazardous waste for energy recovery for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart D;

(3) The waste stream is treated by a means or to a level that meets benzene-specific treatment standards in accordance with the Land Disposal Restrictions under 40 CFR part 268, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of § 61.349 of this subpart;

(4) The waste stream is treated by a means or to a level that meets benzene-specific effluent limitations or performance standards in accordance with the Effluent Guidelines and Standards under 40 CFR parts 401-464, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of § 61.349 of this subpart; or

(5) The waste stream is discharged to an underground injection well for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 122.

(e) Except as specified in paragraph (e)(3) of this section, if the treatment process or wastewater treatment system unit has any openings (e.g., access doors, hatches, etc.), all such openings shall be sealed (e.g., gasketed, latched, etc.) and kept closed at all times when waste is being treated, except during inspection and maintenance.

(1) Each seal, access door, and all other openings shall be checked by visual inspections initially and quarterly thereafter to ensure that no cracks or gaps occur and that openings are closed and gasketed properly.

(2) Except as provided in § 61.350 of this subpart, 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 identification.

(3) If the cover and closed-vent system operate such that the treatment process and wastewater treatment system unit are maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(iii) The pressure is monitored continuously to ensure that the pressure in the treatment process and wastewater treatment system unit remain below atmospheric pressure.

(f) Except for treatment processes complying with paragraph (d) of this section, the Administrator may request at any time an owner or operator demonstrate that a treatment process or wastewater treatment system unit meets the applicable requirements specified in paragraphs (a) or (b) of this section by conducting a performance test using the test methods and procedures as required in § 61.355 of this subpart.

(g) The owner or operator of a treatment process or wastewater treatment system unit that is used to comply with the provisions of this section shall monitor the unit in accordance with the applicable requirements in § 61.354 of this subpart.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.349 Standards: Closed-vent systems and control devices.

(a) For each closed-vent system and control device used to comply with standards in accordance with §§ 61.343 through 61.348 of this subpart, the owner or operator shall properly design, install, operate, and maintain the closed-vent system and control device in accordance with the following requirements:

(1) The closed-vent system shall:

(i) Be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(ii) Vent systems that contain any bypass line that could divert the vent stream away from a control device used to comply with the provisions of this subpart shall install, maintain, and operate according to the manufacturer's specifications a flow indicator that provides a record of vent stream flow away from the control device at least once every 15 minutes, except as provided in paragraph (a)(1)(ii)(B) of this section.

(A) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.

(B) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required.

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

(iv) For each closed-vent system complying with paragraph (a) of this section, one or more devices which vent directly to the atmosphere may be used on the closed-vent system provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the closed-vent system resulting from malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(2) The control device shall be designed and operated in accordance with the following conditions:

(i) An enclosed combustion device (e.g., a vapor incinerator, boiler, or process heater) shall meet one of the following conditions:

(A) Reduce the organic emissions vented to it by 95 weight percent or greater;

(B) Achieve a total organic compound concentration of 20 ppmv (as the sum of the concentrations for individual compounds using Method 18) on a dry basis corrected to 3 percent oxygen; or

(C) Provide a minimum residence time of 0.5 seconds at a minimum temperature of 760 °C (1,400 °F). If a boiler or process heater issued as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(ii) A vapor recovery system (e.g., a carbon adsorption system or a condenser) shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(iii) A flare shall comply with the requirements of 40 CFR 60.18.

(iv) A control device other than those described in paragraphs (a)(2) (i) through (iii) of this section may be used provided that the following conditions are met:

(A) The device shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(B) The owner or operator shall develop test data and design information that documents the control device will achieve an emission control efficiency of either 95 percent or greater for organic compounds or 98 percent or greater for benzene.

(C) The owner or operator shall identify:

(*1*) The critical operating parameters that affect the emission control performance of the device;

(*2*) The range of values of these operating parameters that ensure the emission control efficiency specified in paragraph (a)(2)(iv)(A) of this section is maintained during operation of the device; and

(*3*) How these operating parameters will be monitored to ensure the proper operation and maintenance of the device.

(D) The owner or operator shall submit the information and data specified in paragraphs (a)(2)(iv) (B) and (C) of this section to the Administrator prior to operation of the alternative control device.

(E) The Administrator will determine, based on the information submitted under paragraph (a)(2)(iv)(D) of this section, if the control device subiect to paragraph (a)(2)(iv) of this section meets the requirements of § 61.349. The control device subject to paragraph (a)(2)(iv) of this section may be operated prior to receiving approval from the Administrator. However, if the Administrator determines that the control device does not meet the requirements of § 61.349, the facility may be subject to enforcement action beginning from the time the control device began operation.

(b) Each closed-vent system and control device used to comply with this subpart shall be operated at all times when waste is placed in the waste management unit vented to the control device except when maintenance or repair of the waste management unit cannot be completed without a shutdown of the control device.

(c) An owner and operator shall demonstrate that each control device, except for a flare, achieves the appropriate conditions specified in paragraph (a)(2) of this section by using one of the following methods:

(1) Engineering calculations in accordance with requirements specified in § 61.356(f) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in § 61.355 of this subpart.

(d) An owner or operator shall demonstrate compliance of each flare in accordance with paragraph (a)(2)(iii) of this section.

(e) The Administrator may request at any time an owner or operator demonstrate that a control device meets the applicable conditions specified in paragraph (a)(2) of this section by conducting a performance test using the test methods and procedures as required in § 61.355, and for control devices subject to paragraph (a)(2)(iv) of this section, the Administrator may specify alternative test methods and procedures, as appropriate.

(f) Each closed-vent system and control device shall be visually inspected initially and quarterly thereafter. The visual inspection shall include inspection of ductwork and piping and connections to covers and control devices for evidence of visable defects such as holes in ductwork or piping and loose connections.

(g) Except as provided in § 61.350 of this subpart, if visible defects are observed during an inspection, or if other problems are identified, or if detectable emissions are measured, a first effort to repair the closed-vent system and control device shall be made as soon as practicable but no later than 5 calendar days after detection. Repair shall be completed no later than 15 calendar days after the emissions are detected or the visible defect is observed.

(h) The owner or operator of a control device that is used to comply with the provisions of this section shall monitor the control device in accordance with § 61.354(c) of this subpart.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.350   Standards: Delay of repair.

(a) Delay of repair of facilities or units that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial facility or unit shutdown.

(b) Repair of such equipment shall occur before the end of the next facility or unit shutdown.

§ 61.351   Alternative standards for tanks.

(a) As an alternative to the standards for tanks specified in § 61.343 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A fixed roof and internal floating roof meeting the requirements in 40 CFR 60.112b(a)(1);

(2) An external floating roof meeting the requirements of 40 CFR 60.112b (a)(2); or

(3) An alternative means of emission limitation as described in 40 CFR 60.114b.

(b) If an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions of § 61.343 of this subpart applicable to the same facilities.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990]

§ 61.352   Alternative standards for oil-water separators.

(a) As an alternative to the standards for oil-water separators specified in § 61.347 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A floating roof meeting the requirements in 40 CFR 60.693-2(a); or

(2) An alternative means of emission limitation as described in 40 CFR 60.694.

(b) For portions of the oil-water separator where it is infeasible to construct and operate a floating roof, such as over the weir mechanism, a fixed roof vented to a vapor control device that meets the requirements in §§ 61.347 and 61.349 of this subpart shall be installed and operated.

(c) Except as provided in paragraph (b) of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions in § 61.347 of this subpart applicable to the same facilities.

§ 61.353 Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in benzene emissions at least equivalent to the reduction in benzene emissions from the source achieved by the applicable design, equipment, work practice, or operational requirements in §§ 61.342 through 61.349, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

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

(c) Any person seeking permission under this section shall collect, verify, and submit to the Administrator information showing that the alternative means achieves equivalent emission reductions.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993]

§ 61.354 Monitoring of operations.

(a) Except for a treatment process or waste stream complying with § 61.348(d), the owner or operator shall monitor each treatment process or wastewater treatment system unit to ensure the unit is properly operated and maintained by one of the following monitoring procedures:

(1) Measure the benzene concentration of the waste stream exiting the treatment process complying with § 61.348(a)(1)(i) at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(2) Install, calibrate, operate, and maintain according to manufacturer's specifications equipment to continuously monitor and record a process parameter (or parameters) for the treatment process or wastewater treatment system unit that indicates proper system operation. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the unit is operating properly.

(b) If an owner or operator complies with the requirements of § 61.348(b), then the owner or operator shall monitor each wastewater treatment system to ensure the unit is properly operated and maintained by the appropriate monitoring procedure as follows:

(1) For the first exempt waste management unit in each waste treatment train, other than an enhanced biodegradation unit, measure the flow rate, using the procedures of § 61.355(b), and the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(2) For each enhanced biodegradation unit that is the first exempt waste management unit in a treatment train, measure the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(c) An owner or operator subject to the requirements in § 61.349 of this subpart shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device to continuously monitor the control device operation as specified in the following paragraphs, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the control device is operating properly.

(1) For a thermal vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(2) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

(3) For a flare, a monitoring device in accordance with 40 CFR 60.18(f)(2) equipped with a continuous recorder.

(4) For a boiler or process heater having a design heat input capacity less than 44 MW (150 × 10^6 BTU/hr), a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(5) For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW (150 × 10^6 BTU/hr), a monitoring device equipped with a continuous recorder to measure a parameter(s) that indicates good combustion operating practices are being used.

(6) For a condenser, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the condenser; or

(ii) A temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of ±1 percent of the temperature being monitored in °C or ±0.5 °C, whichever is greater. One temperature sensor shall be installed at a location in the exhaust stream from the condenser, and a second temperature sensor shall be installed at a location in the coolant fluid exiting the condenser.

(7) For a carbon adsorption system that regenerates the carbon bed directly in the control device such as a fixed-bed carbon adsorber, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the carbon bed; or

(ii) A monitoring device equipped with a continuous recorder to measure a parameter that indicates the carbon bed is regenerated on a regular, predetermined time cycle.

(8) For a vapor recovery system other than a condenser or carbon adsorption system, a monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the control device.

(9) For a control device subject to the requirements of § 61.349(a)(2)(iv), devices to monitor the parameters as specified in § 61.349(a)(2)(iv)(C).

(d) For a carbon adsorption system that does not regenerate the carbon bed directly on site in the control device (e.g., a carbon canister), either the concentration level of the organic compounds or the concentration level of benzene 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 either the organic concentration or the benzene concentration in the gas stream vented to the carbon adsorption system.

(e) An alternative operation 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.

(f) Owners or operators using a closed-vent system that contains any bypass line that could divert a vent stream from a control device used to comply with the provisions of this subpart shall do the following:

(1) Visually inspect the bypass line valve at least once every month, checking the position of the valve and the condition of the car-seal or closure mechanism required under § 61.349(a)(1)(ii) to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(2) Visually inspect the readings from each flow monitoring device required by § 61.349(a)(1)(ii) at least once each operating day to check that vapors are being routed to the control device as required.

(g) Each owner or operator who uses a system for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device equipped with a continuous recorder to monitor the pressure in the unit to ensure that it is less than atmospheric pressure.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.355 Test methods, procedures, and compliance provisions.

(a) An owner or operator shall determine the total annual benzene quantity from facility waste by the following procedure:

(1) For each waste stream subject to this subpart having a flow-weighted annual average water content greater than 10 percent water, on a volume basis as total water, or is mixed with water or other wastes at any time and the resulting mixture has an annual average water content greater than 10 percent as specified in § 61.342(a), the owner or operator shall:

(i) Determine the annual waste quantity for each waste stream using the procedures specified in paragraph (b) of this section.

(ii) Determine the flow-weighted annual average benzene concentration for each waste stream using the procedures specified in paragraph (c) of this section.

(iii) Calculate the annual benzene quantity for each waste stream by multiplying the annual waste quantity of the waste stream times the flow-weighted annual average benzene concentration.

(2) Total annual benzene quantity from facility waste is calculated by adding together the annual benzene quantity for each waste stream generated during the year and the annual benzene quantity for each process unit turnaround waste annualized according to paragraph (b)(4) of this section.

(3) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall comply with the requirements of § 61.342 (c), (d), or (e).

(4) If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of § 61.356 and reporting requirements of § 61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste at least once per year and whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more.

(5) If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of § 61.356 and reporting requirements of § 61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

(6) The benzene quantity in a waste stream that is generated less than one time per year, except as provided for process unit turnaround waste in paragraph (b)(4) of this section, shall be included in the determination of total annual benzene quantity from facility waste for the year in which the waste is generated unless the waste stream is otherwise excluded from the determination of total annual benzene quantity from facility waste in accordance with paragraphs (a) through (c) of this section. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste, for purposes of determining the total annual benzene quantity from facility waste.

(b) For purposes of the calculation required by paragraph (a) of this section, an owner or operator shall determine the annual waste quantity at the point of waste generation, unless otherwise provided in paragraphs (b) (1), (2), (3), and (4) of this section, by one of the methods given in paragraphs (b) (5) through (7) of this section.

(1) The determination of annual waste quantity for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(2) The determination of annual waste quantity for wastes at coke by-product plants subject to and complying with the control requirements of § 61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following conditions are met:

(i) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is made through hard piping or other enclosed system.

(ii) The ammonia still meets the definition of a sour water stripper in § 61.341.

(3) The determination of annual waste quantity for wastes that are received at hazardous waste treatment, storage, or disposal facilities from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(4) The determination of annual waste quantity for each process unit turnaround waste generated only at 2 year or greater intervals, may be made by dividing the total quantity of waste generated during the most recent process unit turnaround by the time period (in the nearest tenth of a year) between the turnaround resulting in generation of the waste and the most recent preceding process turnaround for the unit. The resulting annual waste quantity shall be included in the calculation of the annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process turnaround. For estimates of total annual benzene quantity as specified in the 90-day report, required under § 61.357(a)(1), the owner or operator shall estimate the waste quantity generated during the most recent turnaround, and the time period between turnarounds in accordance with good engineering practices. If the owner or operator chooses not to annualize process unit turnaround waste, as specified in this paragraph, then the process unit turnaround waste quantity shall be included in the calculation of the annual benzene quantity for the year in which the turnaround occurs.

(5) Select the highest annual quantity of waste managed from historical records representing the most recent 5 years of operation or, if the facility has been in service for less than 5 years but at least 1 year, from historical records representing the total operating life of the facility;

(6) Use the maximum design capacity of the waste management unit; or

(7) Use measurements that are representative of maximum waste generation rates.

(c) For the purposes of the calculation required by §§ 61.355(a) of this subpart, an owner or operator shall determine the flow-weighted annual average ben- zene concentration in a manner that meets the requirements given in paragraph (c)(1) of this section using either of the methods given in paragraphs (c)(2) and (c)(3) of this section.

(1) The determination of flow-weighted annual average benzene concentration shall meet all of the following criteria:

(i) The determination shall be made at the point of waste generation except for the specific cases given in paragraphs (c)(1)(i)(A) through (D) of this section.

(A) The determination for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(B) The determination for wastes at coke by-product plants subject to and complying with the control requirements of § 61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following conditions are met:

(*1*) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is made through hard piping or other enclosed system.

(*2*) The ammonia still meets the definition of a sour water stripper in § 61.341.

(C) The determination for wastes that are received from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(D) The determination of flow-weighted annual average benzene concentration for process unit turnaround waste shall be made using either of the methods given in paragraph (c)(2) or (c)(3) of this section. The resulting flow-weighted annual average benzene concentration shall be included in the calculation of annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process unit turnaround.

(ii) Volatilization of the benzene by exposure to air shall not be used in the determination to reduce the benzene concentration.

(iii) Mixing or diluting the waste stream with other wastes or other materials shall not be used in the determination—to reduce the benzene concentration.

(iv) The determination shall be made prior to any treatment of the waste that removes benzene, except as specified in paragraphs (c)(1)(i)(A) through (D) of this section.

(v) For wastes with multiple phases, the determination shall provide the weighted-average benzene concentration based on the benzene concentration in each phase of the waste and the relative proportion of the phases.

(2) *Knowledge of the waste.* The owner or operator shall provide sufficient information to document the flow-weighted annual average benzene concentration of each waste stream. Examples of information that could constitute knowledge include material balances, records of chemicals purchases, or previous test results provided the results are still relevant to the current waste stream conditions. If test data are used, then the owner or operator shall provide documentation describing the testing protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the flow-weighted annual average benzene concentration for the waste stream. When an owner or operator and the Administrator do not agree on determinations of the flow-weighted annual average benzene concentration based on knowledge of the waste, the procedures under paragraph (c)(3) of this section shall be used to resolve the disagreement.

(3) Measurements of the benzene concentration in the waste stream in accordance with the following procedures:

(i) Collect a minimum of three representative samples from each waste stream. Where feasible, samples shall be taken from an enclosed pipe prior to the waste being exposed to the atmosphere.

(ii) For waste in enclosed pipes, the following procedures shall be used:

(A) Samples shall be collected prior to the waste being exposed to the atmosphere in order to minimize the loss of benzene prior to sampling.

(B) A static mixer shall be installed in the process line or in a by-pass line unless the owner or operator demonstrates that installation of a static mixer in the line is not necessary to accurately determine the benzene concentration of the waste stream.

(C) The sampling tap shall be located within two pipe diameters of the static mixer outlet.

(D) Prior to the initiation of sampling, sample lines and cooling coil shall be purged with at least four volumes of waste.

(E) After purging, the sample flow shall be directed to a sample container and the tip of the sampling tube shall be kept below the surface of the waste during sampling to minimize contact with the atmosphere.

(F) Samples shall be collected at a flow rate such that the cooling coil is able to maintain a waste temperature less than 10 °C (50 °F).

(G) After filling, the sample container shall be capped immediately (within 5 seconds) to leave a minimum headspace in the container.

(H) The sample containers shall immediately be cooled and maintained at a temperature below 10 °C (50 °F) for transfer to the laboratory.

(iii) When sampling from an enclosed pipe is not feasible, a minimum of three representative samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of benzene prior to sampling.

(iv) Each waste sample shall be analyzed using one of the following test methods for determining the benzene concentration in a waste stream:

(A) Method 8020, Aromatic Volatile Organics, in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(B) Method 8021, Volatile Organic Compounds in Water by Purge and Trap Capillary Column Gas Chromatography with Photoionization and Electrolytic Conductivity Detectors in Series in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(C) Method 8240, Gas Chromatography/Mass Spectrometry for Volatile Organics in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(D) Method 8260, Gas Chromatography/Mass Spectrometry for Volatile Organics: Capillary Column Technique in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(E) Method 602, Purgeable Aromatics, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA methods; or

(F) Method 624, Purgeables, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA method.

(v) The flow-weighted annual average benzene concentration shall be calculated by averaging the results of the sample analyses as follows:

$$\bar{C} = \frac{1}{Q_t} \times \sum_{i=1}^{n} (Q_i)(C_i)$$

Where:

$\bar{C}$=Flow-weighted annual average benzene concentration for waste stream, ppmw.

Q_t =Total annual waste quantity for waste stream, kg/yr (lb/yr).

n=Number of waste samples (at least 3).

Q_i =Annual waste quantity for waste stream represented by C_i , kg/yr (lb/yr).

C_i =Measured concentration of benzene in waste sample i, ppmw.

(d) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348 (a)(1)(i) shall measure the flow-weighted annual average benzene concentration of the waste stream exiting the treatment process by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(e) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348(a)(1)(ii) of this subpart shall determine the percent reduction of benzene in the waste stream on a mass basis by the following procedure:

(1) The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the treatment process (E_b) shall be determined by computing the product of the flow rate of the waste stream entering the treatment process, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene entering the treatment process is calculated as follows:

$$E_b = \frac{K}{n \times 10^6} \left[\sum_{i=1}^{n} V_i C_i \right]$$

Where:

E_b = Mass flow rate of benzene entering the treatment process, kg/hr (lb/hr).

K = Density of the waste stream, kg/m^3 (lb/ft^3).

V_i = Average volume flow rate of waste entering the treatment process during each run i, m^3 /hr (ft^3 /hr).

C_i = Average concentration of benzene in the waste stream entering the treatment process during each run i, ppmw.

n = Number of runs.

10^6 = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the treatment process (E_a) shall be determined by computing the product of the flow rate of the waste stream exiting the treatment process, as determined by the outlet flow meter or the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over the same 3-hour period at which the mass flow rate of benzene entering the treatment process is determined. The mass flow rate of benzene exiting the treatment process is calculated as follows:

$$E_a = \frac{K}{n \times 10^6}\left[\sum_{i-1}^{n} V_i C_i\right]$$

Where:

E_a = Mass flow rate of benzene exiting the treatment process, kg/hr (lb/hr).

K = Density of the waste stream, kg/m^3 (lb/ft^3).

V_i = Average volume flow rate of waste exiting the treatment process during each run i, m^3 /hr (ft^3 /hr).

C_i = Average concentration of benzene in the waste stream exiting the treatment process during each run i, ppmw.

n = Number of runs.

10^6 = Conversion factor for ppmw.

(f) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348(a)(1)(iii) of this subpart shall determine the benzene destruction efficiency for the combustion unit by the following procedure:

(1) The test shall be conducted under conditions that exist when the combustion unit is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the combustion unit shall be determined by computing the product of the flow rate of the waste stream entering the combustion unit, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling procedures in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene into the combustion unit is calculated as follows:

$$E_b = \frac{K}{n \times 10^6}\left[\sum_{i-1}^{n} V_i C_i\right]$$

Where:

E_b = Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).

K = Density of the waste stream, kg/m^3 (lb/ft^3).

V_i = Average volume flow rate of waste entering the combustion unit during each run i, m^3 /hr (ft^3 /hr).

C_i = Average concentration of benzene in the waste stream entering the combustion unit during each run i, ppmw.

n = Number of runs.

10^6 = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the combustion unit exhaust stack shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which at least 3 stack gas samples are collected and be the same time period at which the mass flow rate of benzene entering the treatment process is determined. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample and each 1-hour period shall correspond to the periods when the waste feed is sampled.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate.

(C) The average benzene concentration in the exhaust downstream of the combustion unit shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of benzene emitted during each run shall be calculated as follows:

$$M_i = D_b VC\left(10^{-6}\right)$$

Where:

M_i = Mass of benzene emitted during run i, kg (lb).

V = Volume of air-vapor mixture exhausted at standard conditions, m^3 (ft^3).

C = Concentration of benzene measured in the exhaust, ppmv.

D_b = Density of benzene, 3.24 kg/m^3 (0.202 lb/ft^3).

10^6 = Conversion factor for ppmv.

(iv) The benzene mass emission rate in the exhaust shall be calculated as follows:

$$E_a = \left(\sum_{i=1}^{n} M_i\right) / T$$

Where:

E_a = Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).

M_i = Mass of benzene emitted from the combustion unit during run i, kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(5) The benzene destruction efficiency for the combustion unit shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b} \times 100$$

Where:

R = Benzene destruction efficiency for the combustion unit, percent.

E_b = Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).

E_a = Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).

(g) An owner or operator using performance tests to demonstrate compliance of a wastewater treatment system unit with § 61.348(b) shall measure the flow-weighted annual average benzene concentration of the wastewater stream where the waste stream enters an exempt waste management unit by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the wastewater treatment system is operating at the highest inlet wastewater stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(h) An owner or operator shall test equipment for compliance with no detectable emissions as required in §§ 61.343 through 61.347, and § 61.349 of this subpart in accordance with the following requirements:

(1) Monitoring shall comply with Method 21 from appendix A of 40 CFR part 60.

(2) The detection instrument shall meet the performance criteria of Method 21.

(3) The instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21.

(4) Calibration gases shall be:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

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

(5) The background level shall be determined as set forth in Method 21.

(6) The instrument probe shall be traversed around all potential leak interfaces as close as possible to the interface as described in Method 21.

(7) The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared to 500 ppm for determining compliance.

(i) An owner or operator using a performance test to demonstrate compliance of a control device with either the organic reduction efficiency requirement or the benzene reduction efficiency requirement specified under § 61.349(a)(2) shall use the following procedures:

(1) The test shall be conducted under conditions that exist when the waste management unit vented to the control device is operating at the highest load or capacity level expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) Sampling sites shall be selected using Method 1 or 1A from appendix A of 40 CFR part 60, as appropriate.

(3) The mass flow rate of either the organics or benzene entering and exiting the control device shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which at least 3 stack gas samples are collected. Samples of the vent stream entering and exiting the control device shall be collected during the same time period. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate;

(C) The organic concentration or the benzene concentration, as appropriate, in the vent stream entering and exiting the control shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of organics or benzene entering and exiting the control device during each run shall be calculated as follows:

$$M_{aj} = \frac{K_1 V_{aj}}{10^6}\left(\sum_{i=1}^{n} C_{ai} MW_i\right) \quad M_{bj} = \frac{K_1 V_{bj}}{10^6}\left(\sum_{i=1}^{n} C_{bi} MW_i\right)$$

M_{aj} = Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

M_{bj} = Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

V_{aj} = Volume of vent stream entering the control device during run j, at standard conditions, m^3 (ft^3).

V_{bj} = Volume of vent stream exiting the control device during run j, at standard conditions, m^3 (ft^3).

C_{ai} = Organic concentration of compound i or the benzene concentration measured in the vent stream entering the control device as determined by Method 18, ppm by volume on a dry basis.

C_{bi} = Organic concentration of compound i or the benzene concentration measured in the vent stream exiting the control device as determined by Method 18, ppm by volume on a dry basis.

MW_i = Molecular weight of organic compound i in the vent stream, or the molecular weight of benzene, kg/kg-mol (lb/lb-mole).

n = Number of organic compounds in the vent stream; if benzene reduction efficiency is being demonstrated, then n=1.

K_1 = Conversion factor for molar volume at standard conditions (293 K and 760 mm Hg (527 R and 14.7 psia))

= 0.0416 kg-mol/m^3 (0.00118 lb-mol/ft^3)

10^{-6} =Conversion factor for ppmv.

(iv) The mass flow rate of organics or benzene entering and exiting the control device shall be calculated as follows:

$$E_a - \left(\sum_{j-1}^{n} M_{aj}\right) / T$$

$$E_b - \left(\sum_{j-1}^{n} M_{bj}\right) / T$$

Where:

E_a = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

E_b = Mass flow rate of organics or benzene exiting the control device, kg/hr (lb/hr).

M_{aj} = Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

M_{bj} = Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(4) The organic reduction efficiency or the benzene reduction efficiency for the control device shall be calculated as follows:

$$R = \frac{E_a - E_b}{E_a} \times 100$$

Where:

R = Total organic reduction of efficiency or benzene reduction efficiency for the control device, percent.

E_b = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

E_a = Mass flow rate of organic or benzene emitted from the control device, kg/hr (lb/hr).

(j) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by § 61.342 (c)(3)(ii)(B) according to the provisions of paragraph (a) of this section, except that the procedures in paragraph (a) of this section shall also apply to wastes with a water content of 10 percent or less.

(k) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by § 61.342(e)(2) by the following procedure:

(1) For each waste stream that is not controlled for air emissions in accordance with § 61.343. 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the benzene quantity shall be determined as specified in paragraph (a) of this section, except that paragraph (b)(4) of this section shall not apply, i.e., the waste quantity for process unit turnaround waste is not annualized but shall be included in the determination of benzene quantity for the year in which the waste is generated for the purposes of the calculation required by § 61.342(e)(2).

(2) For each waste stream that is controlled for air emissions in accordance with § 61.343. 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the determination of annual waste quantity and flow-weighted annual average benzene concentration shall be made at the first applicable location as described in paragraphs (k)(2)(i), (k)(2)(ii), and (k)(2)(iii) of this section and prior to any reduction of benzene concentration through volatilization of the benzene, using the methods given in (k)(2)(iv) and (k)(2)(v) of this section.

(i) Where the waste stream enters the first waste management unit not complying with §§ 61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a) that are applicable to the waste management unit,

(ii) For each waste stream that is managed or treated only in compliance with §§ 61.343 through 61.348(a) up to the point of final direct discharge from the facility, the determination of benzene quantity shall be prior to any reduction of benzene concentration through volatilization of the benzene, or

(iii) For wastes managed in units controlled for air emissions in accordance with §§ 61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a), and then transferred offsite, facilities shall use the first applicable offsite location as described in paragraphs (k)(2)(i) and (k)(2)(ii) of this section if they have documentation from the offsite facility of the benzene quantity at this location. Facilities without this documentation for offsite wastes shall use the benzene quantity determined at the point where the transferred waste leaves the facility.

(iv) Annual waste quantity shall be determined using the procedures in paragraphs (b)(5), (6), or (7) of this section, and

(v) The flow-weighted annual average benzene concentration shall be determined using the procedures in paragraphs (c)(2) or (3) of this section.

(3) The benzene quantity in a waste stream that is generated less than one time per year, including process unit turnaround waste, shall be included in the determination of benzene quantity as determined in paragraph (k)(6) of this section for the year in which the waste is generated. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste for purposes of determining benzene quantity as determined in paragraph (k)(6) of this section.

(4) The benzene in waste entering an enhanced biodegradation unit, as defined in § 61.348(b)(2)(ii)(B), shall not be included in the determination of benzene quantity, determined in paragraph (k)(6) of this section, if the following conditions are met:

(i) The benzene concentration for each waste stream entering the enhanced biodegradation unit is less than 10 ppmw on a flow-weighted annual average basis, and

(ii) All prior waste management units managing the waste comply with §§ 61.343, 61.344, 61.345, 61.346, 61.347 and 61.348(a).

(5) The benzene quantity for each waste stream in paragraph (k)(2) of this section shall be determined by multiplying the annual waste quantity of each waste stream times its flow-weighted annual average benzene concentration.

(6) The total benzene quantity for the purposes of the calculation required by § 61.342(e)(2) shall be determined by adding together the benzene quantities determined in paragraphs (k)(1) and (k)(5) of this section for each applicable waste stream.

(7) If the benzene quantity determined in paragraph (6) of this section exceeds 6.0 Mg/yr (6.6 ton/yr) only because of multiple counting of the benzene quantity for a waste stream, the owner or operator may use the following procedures for the purposes of the calculation required by § 61.342(e)(2):

(i) Determine which waste management units are involved in the multiple counting of benzene;

(ii) Determine the quantity of benzene that is emitted, recovered, or removed from the affected units identified in paragraph (k)(7)(i) of this section, or destroyed in the units if applicable, using either direct measurements or the best available estimation techniques developed or approved by the Administrator.

(iii) Adjust the benzene quantity to eliminate the multiple counting of benzene based on the results from paragraph (k)(7)(ii) of this section and determine the total benzene quantity for the purposes of the calculation required by § 61.342(e)(2).

(iv) Submit in the annual report required under § 61.357(a) a description of the methods used and the resulting calculations for the alternative procedure under paragraph (k)(7) of this section, the benzene quantity determination from paragraph (k)(6) of this section, and the adjusted benzene quantity determination from paragraph (k)(7)(iii) of this section.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

§ 61.356 Recordkeeping requirements.

(a) Each owner or operator of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. Each record shall be maintained in a readily accessible location at the facility site for a period not less than two years from the date the information is recorded unless otherwise specified.

(b) Each owner or operator shall maintain records that identify each waste stream at the facility subject to this subpart, and indicate whether or not the waste stream is controlled for benzene emissions in accordance with this subpart. In addition the owner or operator shall maintain the following records:

(1) For each waste stream not controlled for benzene emissions in accordance with this subpart, the records shall include all test results, measurements, calculations, and other documentation used to determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is a process wastewater stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(2) For each waste stream exempt from § 61.342(c)(1) in accordance with § 61.342(c)(3), the records shall include:

(i) All measurements, calculations, and other documentation used to determine that the continuous flow of process wastewater is less than 0.02 liters (0.005 gallons) per minute or the annual waste quantity of process wastewater is less than 10 Mg/yr (11 ton/yr) in accordance with § 61.342(c)(3)(i), or

(ii) All measurements, calculations, and other documentation used to determine that the sum of the total annual benzene quantity in all exempt waste streams does not exceed 2.0 Mg/yr (2.2 ton/yr) in accordance with § 61.342(c)(3)(ii).

(3) For each facility where process wastewater streams are controlled for benzene emissions in accordance with § 61.342(d) of this subpart, the records shall include for each treated process wastewater stream all measurements, calculations, and other documentation used to determine the annual benzene quantity in the process wastewater stream exiting the treatment process.

(4) For each facility where waste streams are controlled for benzene emissions in accordance with § 61.342(e), the records shall include for each waste stream all measurements, including the locations of the measurements, calculations, and other documentation used to determine that the total benzene quantity does not exceed 6.0 Mg/yr (6.6 ton/yr).

(5) For each facility where the annual waste quantity for process unit turnaround waste is determined in accordance with § 61.355(b)(5), the records shall include all test results, measurements, calculations, and other documentation used to determine the following information: identification of each process unit at the facility that undergoes turnarounds, the date of the most recent turnaround for each process unit, identification of each process unit turnaround waste, the water content of each process unit turnaround waste, the annual waste quantity determined in accordance with § 61.355(b)(5), the range of benzene concentrations in the waste, the annual average flow-weighted benzene concentration of the waste, and the annual benzene quantity calculated in accordance with § 61.355(a)(1)(iii) of this section.

(6) For each facility where wastewater streams are controlled for benzene emissions in accordance with § 61.348(b)(2), the records shall include all measurements, calculations, and other documentation used to determine the annual benzene content of the waste streams and the total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units.

(c) An owner or operator transferring waste off-site to another facility for treatment in accordance with § 61.342(f) shall maintain documentation for each offsite waste shipment that includes the following information: Date waste is shipped offsite, quantity of waste shipped offsite, name and address of the facility receiving the waste, and a copy of the notice sent with the waste shipment.

(d) An owner or operator using control equipment in accordance with §§ 61.343 through 61.347 shall maintain engineering design documentation for all control equipment that is installed on the waste management unit. The documentation shall be retained for the life of the control equipment. If a control device is used, then the owner or operator shall maintain the control device records required by paragraph (f) of this section.

(e) An owner or operator using a treatment process or wastewater treatment system unit in accordance with § 61.348 of this subpart shall maintain the following records. The documentation shall be retained for the life of the unit.

(1) A statement signed and dated by the owner or operator certifying that the unit is designed to operate at the documented performance level when the waste stream entering the unit is at the highest waste stream flow rate and benzene content expected to occur.

(2) If engineering calculations are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain the complete design analysis for the unit. The design analysis shall include for example the following information: Design specifications, drawings, schematics, piping and instrumentation diagrams, and other documentation necessary to demonstrate the unit performance.

(3) If performance tests are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain all test information necessary to demonstrate the unit performance.

(i) A description of the unit including the following information: type of treatment process; manufacturer name and model number; and for each waste stream entering and exiting the unit, the waste stream type (e.g., process wastewater, sludge, slurry, etc.), and the design flow rate and benzene content.

(ii) Documentation describing the test protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the unit performance. The description of the test protocol shall include the following information: sampling locations, sampling method, sampling frequency, and analytical procedures used for sample analysis.

(iii) Records of unit operating conditions during each test run including all key process parameters.

(iv) All test results.

(4) If a control device is used, then the owner or operator shall maintain the control device records required by paragraph (f) of this section.

(f) An owner or operator using a closed-vent system and control device in accordance with § 61.349 of this subpart shall maintain the following records. The documentation shall be retained for the life of the control device.

(1) A statement signed and dated by the owner or operator certifying that the closed-vent system and control device is designed to operate at the documented performance level when the waste management unit vented to the control device is or would be operating at the highest load or capacity expected to occur.

(2) If engineering calculations are used to determine control device performance in accordance with § 61.349(c), then a design analysis for the control device that includes for example:

(i) Specifications, drawings, schematics, and piping and instrumentation diagrams prepared by the owner or operator, or the control device manufacturer or vendor that describe the control device design based on acceptable engineering texts. The design analysis shall address the following vent stream characteristics and control device operating parameters:

(A) For a thermal vapor incinerator, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average temperature in the combustion zone and the combustion zone residence time.

(B) For a catalytic vapor incinerator, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average temperatures across the catalyst bed inlet and outlet.

(C) For a boiler or process heater, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average flame zone temperatures, combustion zone residence time, and description of method and location where the vent stream is introduced into the flame zone.

(D) For a flare, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also consider the requirements specified in 40 CFR 60.18.

(E) For a condenser, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design outlet organic compound concentration level or the design outlet benzene concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(F) For a carbon adsorption system that regenerates the carbon bed directly on-site in the control device such as a fixed-bed adsorber, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, number and capacity of carbon beds, type and working capacity of activated carbon used for carbon beds, design total steam flow over the period of each complete carbon bed regeneration cycle, duration of the carbon bed steaming and cooling/drying cycles, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of carbon.

(G) For a carbon adsorption system that does not regenerate the carbon bed directly on-site in the control device, such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene 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.

(H) For a control device subject to the requirements of § 61.349(a)(2)(iv), the design analysis shall consider the vent stream composition, constituent concentration, and flow rate. The design analysis shall also include all of the information submitted under § 61.349 (a)(2)(iv).

(ii) [Reserved]

(3) If performance tests are used to determine control device performance in accordance with § 61.349(c) of this subpart:

(i) A description of how it is determined that the test is conducted when the waste management unit or treatment process is operating at the highest load or capacity level. This description shall include the estimated or design flow rate and organic content of each vent stream and definition of the acceptable operating ranges of key process and control parameters during the test program.

(ii) A description of the control device including the type of control device, control device manufacturer's name and model number, control device dimensions, capacity, and construction materials.

(iii) A detailed description of sampling and monitoring procedures, including sampling and monitoring locations in the system, the equipment to be used, sampling and monitoring frequency, and planned analytical procedures for sample analysis.

(iv) All test results.

(g) An owner or operator shall maintain a record for each visual inspection required by §§ 61.343 through 61.347 of this subpart that identifies a problem (such as a broken seal, gap or other problem) which could result in benzene emissions. The record shall include the date of the inspection, waste management unit and control equipment location where the problem is identified, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(h) An owner or operator shall maintain a record for each test of no detectable emissions required by §§ 61.343 through 61.347 and § 61.349 of this subpart. The record shall include the following information: date the test is performed, background level measured during test, and maximum concentration indicated by the instrument reading measured for each potential leak interface. If detectable emissions are measured at a leak interface, then the record shall also include the waste management unit, control equipment, and leak interface location where detectable emissions were measured, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(i) For each treatment process and wastewater treatment system unit operated to comply with § 61.348, the owner or operator shall maintain documentation that includes the following information regarding the unit operation:

(1) Dates of startup and shutdown of the unit.

(2) If measurements of waste stream benzene concentration are performed in accordance with § 61.354(a)(1) of this subpart, the owner or operator shall maintain records that include date each test is performed and all test results.

(3) If a process parameter is continuously monitored in accordance with § 61.354(a)(2) of this subpart, the owner or operator shall maintain records that include a description of the operating parameter (or parameters) to be monitored to ensure that the unit will be operated in conformance with these standards and the unit's design specifications, and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the unit.

(4) If measurements of waste stream benzene concentration are performed in accordance with § 61.354(b), the owner or operator shall maintain records that include the date each test is performed and all test results.

(5) Periods when the unit is not operated as designed.

(j) For each control device, the owner or operator shall maintain documentation that includes the following information regarding the control device operation:

(1) Dates of startup and shutdown of the closed-vent system and control device.

(2) A description of the operating parameter (or parameters) to be monitored to ensure that the control device will be operated in conformance with these standards and the control device's design specifications and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the control device.

(3) Periods when the closed-vent system and control device are not operated as designed including all periods and the duration when:

(i) Any valve car-seal or closure mechanism required under § 61.349(a)(1)(ii) is broken or the by-pass line valve position has changed.

(ii) The flow monitoring devices required under § 61.349(a)(1)(ii) indicate that vapors are not routed to the control device as required.

(4) If a thermal vapor incinerator is used, then the owner or operator 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 °C (50 °F) below the design combustion zone temperature.

(5) If a catalytic vapor incinerator is used, then the owner or operator 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 °C (50 °F) below the design gas stream temperature, and records of all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 percent of the design temperature difference.

(6) If a boiler or process heater is used, then the owner or operator shall maintain records of each occurrence when there is a change in the location at which the vent stream is introduced into the flame zone as required by § 61.349(a)(2)(i)(C). For a boiler or process heater having a design heat input capacity less than 44 MW (150 × 106 BTU/hr), the owner or operator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the boiler or process heater 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 °C (50 °F) below the design combustion zone temperature. For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW (150 × 106 BTU/hr), the owner or operator shall maintain continuous records of the parameter(s) monitored in accordance with the requirements of § 61.354(c)(5).

(7) If a flare is used, then the owner or operator shall maintain continuous records of the flare pilot flame monitoring and records of all periods during which the pilot flame is absent.

(8) If a condenser is used, then the owner or operator shall maintain records from the monitoring device of the parameters selected to be monitored in accordance with § 61.354(c)(6). If concentration of organics or concentration of benzene in the control device outlet gas stream is monitored, then the owner or operator shall record all 3-hour periods of operation during which the concentration of organics or the concentration of benzene in the exhaust stream is more than 20 percent greater than the design value. If the temperature of the condenser exhaust stream and coolant fluid is monitored, then the owner or operator shall record all 3-hour periods of operation during which the temperature of the condenser exhaust vent stream is more than 6 °C (11 °F) above the design average exhaust vent stream temperature, or the temperature of the coolant fluid exiting the condenser is more than 6 °C (11 °F) above the design average coolant fluid temperature at the condenser outlet.

(9) If a carbon adsorber is used, then the owner or operator shall maintain records from the monitoring device of the concentration of organics or the concentration of benzene in the control device outlet gas stream. If the concentration of organics or the concentration of benzene in the control device outlet gas stream is monitored, then the owner or operator shall record all 3-hour periods of operation during which the concentration of organics or the concentration of benzene in the exhaust stream is more than 20 percent greater than the design value. If the carbon bed regeneration interval is monitored, then the owner or operator shall record each occurrence when the vent stream continues to flow through the control device beyond the predetermined carbon bed regeneration time.

(10) If a carbon adsorber that is not regenerated directly on site 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 then the existing carbon in the control device is replaced with fresh carbon.

(11) If an alternative operational or process parameter is monitored for a control device, as allowed in § 61.354(e) of this subpart, then the owner or operator shall maintain records of the continuously monitored parameter, including periods when the device is not operated as designed.

(12) If a control device subject to the requirements of § 61.349(a)(2)(iv) is used, then the owner or operator shall maintain records of the parameters that are monitored and each occurrence when the parameters monitored are outside the range of values specified in § 61.349(a)(2)(iv)(C), or other records as specified by the Administrator.

(k) An owner or operator who elects to install and operate the control equipment in § 61.351 of this subpart shall comply with the recordkeeping requirements in 40 CFR 60.115b.

(l) An owner or operator who elects to install and operate the control equipment in § 61.352 of this subpart shall maintain records of the following:

(1) The date, location, and corrective action for each visual inspection required by 40 CFR 60.693-2(a)(5), during which a broken seal, gap, or other problem is identified that could result in benzene emissions.

(2) Results of the seal gap measurements required by 40 CFR 60.693-2(a).

(m) If a system is used for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air, then the owner or operator shall maintain records of the monitoring device and records of all periods during which the pressure in the unit is operated at a pressure that is equal to or greater than atmospheric pressure.

(n) Each owner or operator using a total enclosure to comply with control requirements for tanks in § 61.343 or the control requirements for containers in § 61.345 must keep the records required in paragraphs (n)(1) and (2) of this section. Owners or operators may use records as required in 40 CFR 264.1089(b)(2)(iv) or 40 CFR 265.1090(b)(2)(iv) for a tank or as required in 40 CFR 264.1089(d)(1) or 40 CFR 265.1090(d)(1) for a container to meet the recordkeeping requirement in paragraph (n)(1) of this section. The owner or operator must make the records of each verification of a total enclosure available for inspection upon request.

(1) Records of the most recent set of calculations and measurements performed to verify that the enclosure meets the criteria of a permanent total enclosure as specified in “Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure” in 40 CFR 52.741, appendix B;

(2) Records required for a closed-vent system and control device according to the requirements in paragraphs (d) (f), and (j) of this section.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990; 55 FR 18331, May 2, 1990, as amended at 58 FR 3103, Jan. 7, 1993; 65 FR 62161, Oct. 17, 2000; 67 FR 68533, Nov. 12, 2002]

§ 61.357 Reporting requirements.

(a) Each owner or operator of a chemical plant, petroleum refinery, coke by-product recovery plant, and any facility managing wastes from these industries shall submit to the Administrator within 90 days after January 7, 1993, or by the initial startup for a new source with an initial startup after the effective date, a report that summarizes the regulatory status of each waste stream subject to § 61.342 and is determined by the procedures specified in § 61.355(c) to contain benzene. Each owner or operator subject to this subpart who has no benzene onsite in wastes, products, by-products, or intermediates shall submit an initial report that is a statement to this effect. For all other owners or operators subject to this subpart, the report shall include the following information:

(1) Total annual benzene quantity from facility waste determined in accordance with § 61.355(a) of this subpart.

(2) A table identifying each waste stream and whether or not the waste stream will be controlled for benzene emissions in accordance with the requirements of this subpart.

(3) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart the following information shall be added to the table:

(i) Whether or not the water content of the waste stream is greater than 10 percent;

(ii) Whether or not the waste stream is a process wastewater stream, product tank drawdown, or landfill leachate;

(iii) Annual waste quantity for the waste stream;

(iv) Range of benzene concentrations for the waste stream;

(v) Annual average flow-weighted benzene concentration for the waste stream; and

(vi) Annual benzene quantity for the waste stream.

(4) The information required in paragraphs (a) (1), (2), and (3) of this section should represent the waste stream characteristics based on current configuration and operating conditions. An owner or operator only needs to list in the report those waste streams that contact materials containing benzene. The report does not need to include a description of the controls to be installed to comply with the standard or other information required in § 61.10(a).

(b) If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

(c) If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section. The report shall be submitted annually and whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more. If the information in the annual report required by paragraphs (a)(1) through (a)(3) of this section is not changed in the following year, the owner or operator may submit a statement to that effect.

(d) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall submit to the Administrator the following reports:

(1) Within 90 days after January 7, 1993, unless a waiver of compliance under § 61.11 of this part is granted, or by the date of initial startup for a new source with an initial startup after the effective date, a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests have been carried out in accordance with this subpart. If a waiver of compliance is granted under § 61.11, the certification of equipment necessary to comply with these standards shall be submitted by the date the waiver of compliance expires.

(2) Beginning on the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section. If the information in the annual report required by paragraphs (a)(1) through (a)(3) of this section is not changed in the following year, the owner or operator may submit a statement to that effect.

(3) If an owner or operator elects to comply with the requirements of § 61.342(c)(3)(ii), then the report required by paragraph (d)(2) of this section shall include a table identifying each waste stream chosen for exemption and the total annual benzene quantity in these exempted streams.

(4) If an owner or operator elects to comply with the alternative requirements of § 61.342(d) of this subpart, then he shall include in the report required by paragraph (d)(2) of this section a table presenting the following information for each process wastewater stream:

(i) Whether or not the process wastewater stream is being controlled for benzene emissions in accordance with the requirements of this subpart;

(ii) For each process wastewater stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart, the table shall report the following information for the process wastewater stream as determined at the point of waste generation: annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity;

(iii) For each process wastewater stream identified as being controlled for benzene emissions in accordance with the requirements of this subpart, the table shall report the following information for the process wastewater stream as determined at the exit to the treatment process: Annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(5) If an owner or operator elects to comply with the alternative requirements of § 61.342(e), then the report required by paragraph (d)(2) of this section shall include a table presenting the following information for each waste stream:

(i) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart; the table shall report the following information for the waste stream as determined at the point of waste generation: annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity;

(ii) For each waste stream identified as being controlled for benzene emissions in accordance with the requirements of this subpart; the table shall report the following information for the waste stream as determined at the applicable location described in § 61.355(k)(2): Annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(6) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit quarterly to the Administrator a certification that all of the required inspections have been carried out in accordance with the requirements of this subpart.

(7) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit a report quarterly to the Administrator that includes:

(i) If a treatment process or wastewater treatment system unit is monitored in accordance with § 61.354(a)(1) of this subpart, then each period of operation during which the concentration of benzene in the monitored waste stream exiting the unit is equal to or greater than 10 ppmw.

(ii) If a treatment process or wastewater treatment system unit is monitored in accordance with § 61.354(a)(2) of this subpart, then each 3-hour period of operation during which the average value of the monitored parameter is outside the range of acceptable values or during which the unit is not operating as designed.

(iii) If a treatment process or wastewater treatment system unit is monitored in accordance with § 61.354(b), then each period of operation during which the flow-weighted annual average concentration of benzene in the monitored waste stream entering the unit is equal to or greater than 10 ppmw and/or the total annual benzene quantity is equal to or greater than 1.0 mg/yr.

(iv) For a control device monitored in accordance with § 61.354(c) of this subpart, each period of operation monitored during which any of the following conditions occur, as applicable to the control device:

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

(B) Each 3-hour period of operation during which the average temperature of the gas stream immediately before the catalyst bed of a catalytic vapor incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °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.

(C) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a boiler or process heater having a design heat input capacity less than 44 MW (150 × 106 BTU/hr), as mesured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature.

(D) Each 3-hour period of operation during which the average concentration of organics or the average concentration of benzene in the exhaust gases from a carbon adsorber, condenser, or other vapor recovery system is more than 20 percent greater than the design concentration level of organics or benzene in the exhaust gas.

(E) Each 3-hour period of operation during which the temperature of the condenser exhaust vent stream is more than 6 °C (11 °F) above the design average exhaust vent stream temperature, or the temperature of the coolant fluid exiting the condenser is more than 6 °C (11 °F) above the design average coolant fluid temperature at the condenser outlet.

(F) Each period in which the pilot flame of a flare is absent.

(G) Each occurrence when there is a change in the location at which the vent stream is introduced into the flame zone of a boiler or process heater as required by § 61.349(a)(2)(i)(C) of this subpart.

(H) Each occurrence when the carbon in a carbon adsorber system that is regenerated directly on site in the control device is not regenerated at the predetermined carbon bed regeneration time.

(I) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly on site in the control device is not replaced at the predetermined interval specified in § 61.354(c) of this subpart.

(J) Each 3-hour period of operation during which the parameters monitored are outside the range of values specified in § 61.349(a)(2)(iv)(C), or any other periods specified by the Administrator for a control device subject to the requirements of § 61.349(a)(2)(iv).

(v) For a cover and closed-vent system monitored in accordance with § 61.354(g), the owner or operator shall submit a report quarterly to the Administrator that identifies any period in which the pressure in the waste management unit is equal to or greater than atmospheric pressure.

(8) Beginning one year after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Administrator a report that summarizes all inspections required by §§ 61.342 through 61.354 during which detectable emissions are measured or a problem (such as a broken seal, gap or other problem) that could result in benzone emissions is identified, including information about the repairs or corrective action taken.

(e) An owner or operator electing to comply with the provisions of §§ 61.351 or 61.352 of this subpart shall notify the Administrator of the alternative standard selected in the report required under § 61.07 or § 61.10 of this part.

(f) An owner or operator who elects to install and operate the control equipment in § 61.351 of this subpart shall comply with the reporting requirements in 40 CFR 60.115b.

(g) An owner or operator who elects to install and operate the control equipment in § 61.352 of this subpart shall submit initial and quarterly reports that identify all seal gap measurements, as required in 40 CFR 60.693-2(a), that are outside the prescribed limits.

[55 FR 8346, Mar. 7 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3105, Jan. 7, 1993; 65 FR 62161, Oct. 17, 2000]

§ 61.358 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(d) of the Clean Air Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Alternative means of emission limitation under § 61.353 of this subpart will not be delegated to States.

§ 61.359 [Reserved]

Attachment N

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on July 19, 2016]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart CC—National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

Source: 60 FR 43260, Aug. 18, 1995, unless otherwise noted.

§63.640 Applicability and designation of affected source.

(a) This subpart applies to petroleum refining process units and to related emissions points that are specified in paragraphs (c)(1) through (9) of this section that are located at a plant site and that meet the criteria in paragraphs (a)(1) and (2) of this section:

(1) Are located at a plant site that is a major source as defined in section 112(a) of the Clean Air Act; and

(2) Emit or have equipment containing or contacting one or more of the hazardous air pollutants listed in table 1 of this subpart.

(b)(1) If the predominant use of the flexible operation unit, as described in paragraphs (b)(1)(i) and (ii) of this section, is as a petroleum refining process unit, as defined in §63.641, then the flexible operation unit shall be subject to the provisions of this subpart.

(i) Except as provided in paragraph (b)(1)(ii) of this section, the predominant use of the flexible operation unit shall be the use representing the greatest annual operating time.

(ii) If the flexible operation unit is used as a petroleum refining process unit and for another purpose equally based on operating time, then the predominant use of the flexible operation unit shall be the use that produces the greatest annual production on a mass basis.

(2) The determination of applicability of this subpart to petroleum refining process units that are designed and operated as flexible operation units shall be reported as specified in §63.655(h)(6)(i).

(c) For the purposes of this subpart, the affected source shall comprise all emissions points, in combination, listed in paragraphs (c)(1) through (9) of this section that are located at a single refinery plant site.

(1) All miscellaneous process vents from petroleum refining process units meeting the criteria in paragraph (a) of this section;

(2) All storage vessels associated with petroleum refining process units meeting the criteria in paragraph (a) of this section;

(3) All wastewater streams and treatment operations associated with petroleum refining process units meeting the criteria in paragraph (a) of this section;

(4) All equipment leaks from petroleum refining process units meeting the criteria in paragraph (a) of this section;

(5) All gasoline loading racks classified under Standard Industrial Classification code 2911 meeting the criteria in paragraph (a) of this section;

(6) All marine vessel loading operations located at a petroleum refinery meeting the criteria in paragraph (a) of this section and the applicability criteria of subpart Y, §63.560;

(7) All storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery meeting the criteria in paragraph (a) of this section; and

(8) All heat exchange systems, as defined in this subpart.

(9) All releases associated with the decoking operations of a delayed coking unit, as defined in this subpart.

(d) The affected source subject to this subpart does not include the emission points listed in paragraphs (d)(1) through (d)(5) of this section.

(1) Stormwater from segregated stormwater sewers;

(2) Spills;

(3) Any pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system that is intended to operate in organic hazardous air pollutant service, as defined in §63.641 of this subpart, for less than 300 hours during the calendar year;

(4) Catalytic cracking unit and catalytic reformer catalyst regeneration vents, and sulfur plant vents; and

(5) Emission points routed to a fuel gas system, as defined in §63.641, provided that on and after January 30, 2019, any flares receiving gas from that fuel gas system are subject to §63.670. No other testing, monitoring, recordkeeping, or reporting is required for refinery fuel gas systems or emission points routed to refinery fuel gas systems.

(e) The owner or operator of a storage vessel constructed on or before August 18, 1994, shall follow the procedures specified in paragraphs (e)(1) and (e)(2) of this section to determine whether a storage vessel is part of a source to which this subpart applies. The owner or operator of a storage vessel constructed after August 18, 1994, shall follow the procedures specified in paragraphs (e)(1), (e)(2)(i), and (e)(2)(ii) of this section to determine whether a storage vessel is part of a source to which this subpart applies.

(1) Where a storage vessel is used exclusively by a process unit, the storage vessel shall be considered part of that process unit.

(i) If the process unit is a petroleum refining process unit subject to this subpart, then the storage vessel is part of the affected source to which this subpart applies.

(ii) If the process unit is not subject to this subpart, then the storage vessel is not part of the affected source to which this subpart applies.

(2) If a storage vessel is not dedicated to a single process unit, then the applicability of this subpart shall be determined according to the provisions in paragraphs (e)(2)(i) through (e)(2)(iii) of this section.

(i) If a storage vessel is shared among process units and one of the process units has the predominant use, as determined by paragraphs (e)(2)(i)(A) and (e)(2)(i)(B) of this section, then the storage vessel is part of that process unit.

(A) If the greatest input on a volume basis into the storage vessel is from a process unit that is located on the same plant site, then that process unit has the predominant use.

(B) If the greatest input on a volume basis into the storage vessel is provided from a process unit that is not located on the same plant site, then the predominant use shall be the process unit that receives the greatest amount of material on a volume basis from the storage vessel at the same plant site.

(ii) If a storage vessel is shared among process units so that there is no single predominant use, and at least one of those process units is a petroleum refining process unit subject to this subpart, the storage vessel shall be considered to be part of the petroleum refining process unit that is subject to this subpart. If more than one petroleum refining process unit is subject to this subpart, the owner or operator may assign the storage vessel to any of the petroleum refining process units subject to this subpart.

(iii) If the predominant use of a storage vessel varies from year to year, then the applicability of this subpart shall be determined based on the utilization of that storage vessel during the year preceding August 18, 1995. This determination shall be reported as specified in §63.655(h)(6)(ii).

(f) The owner or operator of a distillation unit constructed on or before August 18, 1994, shall follow the procedures specified in paragraphs (f)(1) through (f)(4) of this section to determine whether a miscellaneous process vent from a distillation unit is part of a source to which this subpart applies. The owner or operator of a distillation unit constructed after August 18, 1994, shall follow the procedures specified in paragraphs (f)(1) through (f)(5) of this section to determine whether a miscellaneous process vent from a distillation unit is part of a source to which this subpart applies.

(1) If the greatest input to the distillation unit is from a process unit located on the same plant site, then the distillation unit shall be assigned to that process unit.

(2) If the greatest input to the distillation unit is provided from a process unit that is not located on the same plant site, then the distillation unit shall be assigned to the process unit located at the same plant site that receives the greatest amount of material from the distillation unit.

(3) If a distillation unit is shared among process units so that there is no single predominant use, as described in paragraphs (f)(1) and (f)(2) of this section, and at least one of those process units is a petroleum refining process unit subject to this subpart, the distillation unit shall be assigned to the petroleum refining process unit that is subject to this subpart. If more than one petroleum refining process unit is subject to this subpart, the owner or operator may assign the distillation unit to any of the petroleum refining process units subject to this rule.

(4) If the process unit to which the distillation unit is assigned is a petroleum refining process unit subject to this subpart and the vent stream contains greater than 20 parts per million by volume total organic hazardous air pollutants, then the vent from the distillation unit is considered a miscellaneous process vent (as defined in §63.641 of this subpart) and is part of the source to which this subpart applies.

(5) If the predominant use of a distillation unit varies from year to year, then the applicability of this subpart shall be determined based on the utilization of that distillation unit during the year preceding August 18, 1995. This determination shall be reported as specified in §63.655(h)(6)(iii).

(g) The provisions of this subpart do not apply to the processes specified in paragraphs (g)(1) through (g)(7) of this section.

(1) Research and development facilities, regardless of whether the facilities are located at the same plant site as a petroleum refining process unit that is subject to the provisions of this subpart;

(2) Equipment that does not contain any of the hazardous air pollutants listed in table 1 of this subpart that is located within a petroleum refining process unit that is subject to this subpart;

(3) Units processing natural gas liquids;

(4) Units that are used specifically for recycling discarded oil;

(5) Shale oil extraction units;

(6) Ethylene processes; and

(7) Process units and emission points subject to subparts F, G, H, and I of this part.

(h) Sources subject to this subpart are required to achieve compliance on or before the dates specified in table 11 of this subpart, except as provided in paragraphs (h)(1) through (3) of this section.

(1) Marine tank vessels at existing sources shall be in compliance with this subpart, except for §§63.657 through 63.660, no later than August 18, 1999, unless the vessels are included in an emissions average to generate emission credits. Marine tank vessels used to generate credits in an emissions average shall be in compliance with this subpart no later than August 18, 1998, unless an extension has been granted by the Administrator as provided in §63.6(i).

(2) Existing Group 1 floating roof storage vessels meeting the applicability criteria in item 1 of the definition of Group 1 storage vessel shall be in compliance with §63.646 at the first degassing and cleaning activity after August 18, 1998, or August 18, 2005, whichever is first.

(3) An owner or operator may elect to comply with the provisions of §63.648(c) through (i) as an alternative to the provisions of §63.648(a) and (b). In such cases, the owner or operator shall comply no later than the dates specified in paragraphs (h)(3)(i) through (iii) of this section.

(i) Phase I (see table 2 of this subpart), beginning on August 18, 1998;

(ii) Phase II (see table 2 of this subpart), beginning no later than August 18, 1999; and

(iii) Phase III (see table 2 of this subpart), beginning no later than February 18, 2001.

(i) If an additional petroleum refining process unit is added to a plant site that is a major source as defined in section 112(a) of the Clean Air Act, the addition shall be subject to the requirements for a new source if it meets the criteria specified in paragraphs (i)(1) through (i)(3) of this section:

(1) It is an addition that meets the definition of construction in §63.2 of subpart A of this part;

(2) Such construction commenced after July 14, 1994; and

(3) The addition has the potential to emit 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.

(j) If any change is made to a petroleum refining process unit subject to this subpart, the change shall be subject to the requirements for a new source if it meets the criteria specified in paragraphs (j)(1) and (j)(2) of this section:

(1) It is a change that meets the definition of reconstruction in §63.2 of subpart A of this part; and

(2) Such reconstruction commenced after July 14, 1994.

(k) If an additional petroleum refining process unit is added to a plant site or a change is made to a petroleum refining process unit and the addition or change is determined to be subject to the new source requirements according to paragraphs (i) or (j) of this section it must comply with the requirements specified in paragraphs (k)(1) and (k)(2) of this section:

(1) The reconstructed source, addition, or change shall be in compliance with the new source requirements in item (1), (2), or (3) of table 11 of this subpart, as applicable, upon initial startup of the reconstructed source or by August 18, 1995, whichever is later; and

(2) The owner or operator of the reconstructed source, addition, or change shall comply with the reporting and recordkeeping requirements that are applicable to new sources. The applicable reports include, but are not limited to:

(i) The application for approval of construction or reconstruction shall be submitted as soon as practical before the construction or reconstruction is planned to commence (but it need not be sooner than November 16, 1995);

(ii) The Notification of Compliance Status report as required by §63.655(f) for a new source, addition, or change;

(iii) Periodic Reports and other reports as required by §63.655(g) and (h);

(iv) Reports and notifications required by §60.487 of subpart VV of part 60 or §63.182 of subpart H of this part. The requirements for subpart H are summarized in table 3 of this subpart;

(v) Reports required by 40 CFR 61.357 of subpart FF;

(vi) Reports and notifications required by §63.428(b), (c), (g)(1), (h)(1) through (h)(3), and (k) of subpart R. These requirements are summarized in table 4 of this subpart; and

(vii) Reports and notifications required by §§63.565 and 63.567 of subpart Y of this part. These requirements are summarized in table 5 of this subpart.

(l) If an additional petroleum refining process unit is added to a plant site or if a miscellaneous process vent, storage vessel, gasoline loading rack, marine tank vessel loading operation, heat exchange system, or decoking operation that meets the criteria in paragraphs (c)(1) through (9) of this section is added to an existing petroleum refinery or if another deliberate operational process change creating an additional Group 1 emissions point(s) (as defined in §63.641) is made to an existing petroleum refining process unit, and if the addition or process change is not subject to the new source requirements as determined according to paragraph (i) or (j) of this section, the requirements in paragraphs (l)(1) through (4) of this section shall apply. Examples of process changes include, but are not limited to, changes in production capacity, or feed or raw material where the change requires construction or physical alteration of the existing equipment or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. For purposes of this paragraph (l) and paragraph (m) of this section, process changes do not include: Process upsets, unintentional temporary process changes, and changes that are within the equipment configuration and operating conditions documented in the Notification of Compliance Status report required by §63.655(f).

(1) The added emission point(s) and any emission point(s) within the added or changed petroleum refining process unit are subject to the requirements for an existing source.

(2) The added emission point(s) and any emission point(s) within the added or changed petroleum refining process unit shall be in compliance with the applicable requirements in item (4) of table 11 of this subpart by the dates specified in paragraph (l)(2)(i) or (ii) of this section.

(i) If a petroleum refining process unit is added to a plant site or an emission point(s) is added to any existing petroleum refining process unit, the added emission point(s) shall be in compliance upon initial startup of any added petroleum refining process unit or emission point(s) or by the applicable compliance date in item (4) of table 11 of this subpart, whichever is later.

(ii) If a deliberate operational process change to an existing petroleum refining process unit causes a Group 2 emission point to become a Group 1 emission point (as defined in §63.641), the owner or operator shall be in compliance upon initial startup or by August 18, 1998, whichever is later, unless the owner or operator demonstrates to the Administrator that achieving compliance will take longer than making the change. If this demonstration is made to the Administrator's satisfaction, the owner or operator shall follow the procedures in paragraphs (m)(1) through (m)(3) of this section to establish a compliance date.

(3) The owner or operator of a petroleum refining process unit or of a storage vessel, miscellaneous process vent, wastewater stream, gasoline loading rack, marine tank vessel loading operation, heat exchange system, or decoking operation meeting the criteria in paragraphs (c)(1) through (9) of this section that is added to a plant site and is subject to the requirements for existing sources shall comply with the reporting and recordkeeping requirements that are applicable to existing sources including, but not limited to, the reports listed in paragraphs (l)(3)(i) through (vii) of this section. A process change to an existing petroleum refining process unit shall be subject to the reporting requirements for existing sources including, but not limited to, the reports listed in paragraphs (l)(3)(i) through (vii) of this section. The applicable reports include, but are not limited to:

(i) The Notification of Compliance Status report as required by §63.655(f) for the emission points that were added or changed;

(ii) Periodic Reports and other reports as required by §63.655(g) and (h);

(iii) Reports and notifications required by sections of subpart A of this part that are applicable to this subpart, as identified in table 6 of this subpart.

(iv) Reports and notifications required by §63.182, or 40 CFR 60.487. The requirements of subpart H of this part are summarized in table 3 of this subpart;

(v) Reports required by §61.357 of subpart FF;

(vi) Reports and notifications required by §63.428(b), (c), (g)(1), (h)(1) through (h)(3), and (k) of subpart R. These requirements are summarized in table 4 of this subpart; and

(vii) Reports and notifications required by §§63.565 and 63.567 of subpart Y. These requirements are summarized in table 5 of this subpart.

(4) If pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, or instrumentation systems are added to an existing source, they are subject to the equipment leak standards for existing sources in §63.648. A notification of compliance status report shall not be required for such added equipment.

(m) If a change that does not meet the criteria in paragraph (l) of this section is made to a petroleum refining process unit subject to this subpart, and the change causes a Group 2 emission point to become a Group 1 emission point (as defined in §63.641), then the owner or operator shall comply with the applicable requirements of this subpart for existing sources, as specified in item (4) of table 11 of this subpart, for the Group 1 emission point as expeditiously as practicable, but in no event later than 3 years after the emission point becomes Group 1.

(1) The owner or operator shall submit to the Administrator for approval a compliance schedule, along with a justification for the schedule.

(2) The compliance schedule shall be submitted within 180 days after the change is made, unless the compliance schedule has been previously submitted to the permitting authority. If it is not possible to determine until after the change is implemented whether the emission point has become Group 1, the compliance schedule shall be submitted within 180 days of the date when the affect of the change is known to the source. The compliance schedule may be submitted in the next Periodic Report if the change is made after the date the Notification of Compliance Status report is due.

(3) The Administrator shall approve or deny the compliance schedule or request changes within 120 calendar days of receipt of the compliance schedule and justification. Approval is automatic if not received from the Administrator within 120 calendar days of receipt.

(n) Overlap of this subpart with other regulations for storage vessels. As applicable, paragraphs (n)(1), (3), (4), (6), and (7) of this section apply for Group 2 storage vessels and paragraphs (n)(2) and (5) of this section apply for Group 1 storage vessels.

(1) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to the provisions of 40 CFR part 60, subpart Kb, is required to comply only with the requirements of 40 CFR part 60, subpart Kb, except as provided in paragraph (n)(8) of this section. After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to the provisions of 40 CFR part 61, subpart Y, is required to comply only with the requirements of 40 CFR part 61, subpart Y, except as provided in paragraph (n)(10) of this section.

(2) After the compliance dates specified in paragraph (h) of this section, a Group 1 storage vessel that is also subject to 40 CFR part 60, subpart Kb, is required to comply only with either 40 CFR part 60, subpart Kb, except as provided in paragraph (n)(8) of this section or this subpart. After the compliance dates specified in paragraph (h) of this section, a Group 1 storage vessel that is also subject to 40 CFR part 61, subpart Y, is required to comply only with either 40 CFR part 61, subpart Y, except as provided in paragraph (n)(10) of this section or this subpart.

(3) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is part of a new source and is subject to 40 CFR 60.110b, but is not required to apply controls by 40 CFR 60.110b or 60.112b, is required to comply only with this subpart.

(4) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is part of a new source and is subject to 40 CFR 61.270, but is not required to apply controls by 40 CFR 61.271, is required to comply only with this subpart.

(5) After the compliance dates specified in paragraph (h) of this section, a Group 1 storage vessel that is also subject to the provisions of 40 CFR part 60, subpart K or Ka, is required to only comply with the provisions of this subpart.

(6) After compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to the control requirements of 40 CFR part 60, subparts K or Ka is required to comply only with the provisions of 40 CFR part 60, subparts K or Ka except as provided for in paragraph (n)(9) of this section.

(7) After the compliance dates specified in paragraph (h) of this section, a Group 2 storage vessel that is subject to 40 CFR part 60, subparts K or Ka, but not to the control requirements of 40 CFR part 60, subparts K or Ka, is required to comply only with this subpart.

(8) Storage vessels described by paragraph (n)(1) of this section are to comply with 40 CFR part 60, subpart Kb, except as provided in paragraphs (n)(8)(i) through (vi) of this section. Storage vessels described by paragraph (n)(2) electing to comply with part 60, subpart Kb of this chapter shall comply with subpart Kb except as provided in paragraphs (n)(8)(i) through (viii) of this section.

(i) Storage vessels that are to comply with §60.112b(a)(2) of subpart Kb are exempt from the secondary seal requirements of §60.112b(a)(2)(i)(B) during the gap measurements for the primary seal required by §60.113b(b) of subpart Kb.

(ii) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in §60.113b(b) of this chapter or to inspect the vessel to determine compliance with §60.113b(a) of this chapter because the roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either §63.120(b)(7)(i) or (ii) of subpart G (only up to the compliance date specified in paragraph (h) of this section for compliance with §63.660, as applicable) or either §63.1063(c)(2)(iv)(A) or (B) of subpart WW.

(iii) If a failure is detected during the inspections required by §60.113b(a)(2) or during the seal gap measurements required by §60.113b(b)(1), and the vessel cannot be repaired within 45 days and the vessel cannot be emptied within 45 days, the owner or operator may utilize up to two extensions of up to 30 additional calendar days each. The owner or operator is not required to provide a request for the extension to the Administrator.

(iv) If an extension is utilized in accordance with paragraph (n)(8)(iii) of this section, the owner or operator shall, in the next periodic report, identify the vessel, provide the information listed in §60.113b(a)(2) or §60.113b(b)(4)(iii), and describe the nature and date of the repair made or provide the date the storage vessel was emptied.

(v) Owners and operators of storage vessels complying with subpart Kb of part 60 may submit the inspection reports required by §§60.115b(a)(3), (a)(4), and (b)(4) of subpart Kb as part of the periodic reports required by this subpart, rather than within the 30-day period specified in §§60.115b(a)(3), (a)(4), and (b)(4) of subpart Kb.

(vi) The reports of rim seal inspections specified in §60.115b(b)(2) are not required if none of the measured gaps or calculated gap areas exceed the limitations specified in §60.113b(b)(4). Documentation of the inspections shall be recorded as specified in §60.115b(b)(3).

(vii) To be in compliance with §60.112b(a)(1)(iv) or (a)(2)(ii) of this chapter, guidepoles in floating roof storage vessels must be equipped with covers and/or controls (*e.g.,* pole float system, pole sleeve system, internal sleeve system or flexible enclosure system) as appropriate to comply with the “no visible gap” requirement.

(viii) If a flare is used as a control device for a storage vessel, on and after January 30, 2019, the owner or operator must meet the requirements of §63.670 instead of the requirements referenced from part 60, subpart Kb of this chapter for that flare.

(9) Storage vessels described by paragraph (n)(6) of this section that are to comply with 40 CFR part 60, subpart Ka, are to comply with only subpart Ka except as provided for in paragraphs (n)(9)(i) through (n)(9)(iv) of this section.

(i) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in §60.113a(a)(1) of this chapter because the floating roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either §63.120(b)(7)(i) or (ii) of subpart G (only up to the compliance date specified in paragraph (h) of this section for compliance with §63.660, as applicable) or either §63.1063(c)(2)(iv)(A) or (B) of subpart WW.

(ii) If a failure is detected during the seal gap measurements required by §60.113a(a)(1) of subpart Ka, and the vessel cannot be repaired within 45 days and the vessel cannot be emptied within 45 days, the owner or operator may utilize up to 2 extensions of up to 30 additional calendar days each.

(iii) If an extension is utilized in accordance with paragraph (n)(9)(ii) of this section, the owner or operator shall, in the next periodic report, identify the vessel, describe the nature and date of the repair made or provide the date the storage vessel was emptied. The owner or operator shall also provide documentation of the decision to utilize an extension including a description of the failure, documentation that alternate storage capacity is unavailable, and a schedule of actions that will ensure that the control equipment will be repaired or the vessel emptied as soon as possible.

(iv) Owners and operators of storage vessels complying with subpart Ka of part 60 may submit the inspection reports required by §60.113a(a)(1)(i)(E) of subpart Ka as part of the periodic reports required by this subpart, rather than within the 60-day period specified in §60.113a(a)(1)(i)(E) of subpart Ka.

(10) Storage vessels described by paragraph (n)(1) of this section are to comply with 40 CFR part 61, subpart Y, except as provided in paragraphs (n)(10)(i) through (vi) of this section. Storage vessels described by paragraph (n)(2) electing to comply with 40 CFR part 61, subpart Y, shall comply with subpart Y except as provided for in paragraphs (n)(10)(i) through (viii) of this section.

(i) Storage vessels that are to comply with §61.271(b) of this chapter are exempt from the secondary seal requirements of §61.271(b)(2)(ii) of this chapter during the gap measurements for the primary seal required by §61.272(b) of this chapter.

(ii) If the owner or operator determines that it is unsafe to perform the seal gap measurements required in §61.272(b) of this chapter or to inspect the vessel to determine compliance with §61.272(a) of this chapter because the roof appears to be structurally unsound and poses an imminent danger to inspecting personnel, the owner or operator shall comply with the requirements in either §63.120(b)(7)(i) or (ii) of subpart G (only up to the compliance date specified in paragraph (h) of this section for compliance with §63.660, as applicable) or either §63.1063(c)(2)(iv)(A) or (B) of subpart WW.

(iii) If a failure is detected during the inspections required by §61.272(a)(2) of this chapter or during the seal gap measurements required by §61.272(b)(1) of this chapter, and the vessel cannot be repaired within 45 days and the vessel cannot be emptied within 45 days, the owner or operator may utilize up to two extensions of up to 30 additional calendar days each. The owner or operator is not required to provide a request for the extension to the Administrator.

(iv) If an extension is utilized in accordance with paragraph (n)(10)(iii) of this section, the owner or operator shall, in the next periodic report, identify the vessel, provide the information listed in §61.272(a)(2) or (b)(4)(iii) of this chapter, and describe the nature and date of the repair made or provide the date the storage vessel was emptied.

(v) Owners and operators of storage vessels complying with 40 CFR part 61, subpart Y, may submit the inspection reports required by §61.275(a), (b)(1), and (d) of this chapter as part of the periodic reports required by this subpart, rather than within the 60-day period specified in §61.275(a), (b)(1), and (d) of this chapter.

(vi) The reports of rim seal inspections specified in §61.275(d) of this chapter are not required if none of the measured gaps or calculated gap areas exceed the limitations specified in §61.272(b)(4) of this chapter. Documentation of the inspections shall be recorded as specified in §61.276(a) of this chapter.

(vii) To be in compliance with §61.271(a)(6) or (b)(3) of this chapter, guidepoles in floating roof storage vessels must be equipped with covers and/or controls (*e.g.,* pole float system, pole sleeve system, internal sleeve system or flexible enclosure system) as appropriate to comply with the “no visible gap” requirement.

(viii) If a flare is used as a control device for a storage vessel, on and after January 30, 2019, the owner or operator must meet the requirements of §63.670 instead of the requirements referenced from part 61, subpart Y of this chapter for that flare.

(o) Overlap of this subpart CC with other regulations for wastewater.

(1) After the compliance dates specified in paragraph (h) of this section a Group 1 wastewater stream managed in a piece of equipment that is also subject to the provisions of 40 CFR part 60, subpart QQQ is required to comply only with this subpart.

(2) After the compliance dates specified in paragraph (h) of this section a Group 1 or Group 2 wastewater stream that is conveyed, stored, or treated in a wastewater stream management unit that also receives streams subject to the provisions of §§63.133 through 63.147 of subpart G wastewater provisions of this part shall comply as specified in paragraph (o)(2)(i) or (o)(2)(ii) of this section. Compliance with the provisions of paragraph (o)(2) of this section shall constitute compliance with the requirements of this subpart for that wastewater stream.

(i) Comply with paragraphs (o)(2)(i)(A) through (D) of this section.

(A) The provisions in §§63.133 through 63.140 of subpart G for all equipment used in the storage and conveyance of the Group 1 or Group 2 wastewater stream.

(B) The provisions in both 40 CFR part 61, subpart FF and in §§63.138 and 63.139 of subpart G for the treatment and control of the Group 1 or Group 2 wastewater stream.

(C) The provisions in §§63.143 through 63.148 of subpart G for monitoring and inspections of equipment and for recordkeeping and reporting requirements. The owner or operator is not required to comply with the monitoring, recordkeeping, and reporting requirements associated with the treatment and control requirements in 40 CFR part 61, subpart FF, §§61.355 through 61.357.

(D) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of 40 CFR part 61, subpart FF, and subpart G of this part, or the requirements of §63.670.

(ii) Comply with paragraphs (o)(2)(ii)(A) through (C) of this section.

(A) Comply with the provisions of §§63.133 through 63.148 and §§63.151 and 63.152 of subpart G.

(B) For any Group 2 wastewater stream or organic stream whose benzene emissions are subject to control through the use of one or more treatment processes or waste management units under the provisions of 40 CFR part 61, subpart FF on or after December 31, 1992, comply with the requirements of §63.133 through §63.147 of subpart G for Group 1 wastewater streams.

(C) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of 40 CFR part 61, subpart FF, and subpart G of this part, or the requirements of §63.670.

(p) Overlap of subpart CC with other regulations for equipment leaks.

(1) After the compliance dates specified in paragraph (h) of this section, equipment leaks that are also subject to the provisions of 40 CFR parts 60 and 61 standards promulgated before September 4, 2007, are required to comply only with the provisions specified in this subpart.

(2) Equipment leaks that are also subject to the provisions of 40 CFR part 60, subpart GGGa, are required to comply only with the provisions specified in 40 CFR part 60, subpart GGGa.

(q) For overlap of subpart CC with local or State regulations, the permitting authority for the affected source may allow consolidation of the monitoring, recordkeeping, and reporting requirements under this subpart with the monitoring, recordkeeping, and reporting requirements under other applicable requirements in 40 CFR parts 60, 61, or 63, and in any 40 CFR part 52 approved State implementation plan provided the implementation plan allows for approval of alternative monitoring, reporting, or recordkeeping requirements and provided that the permit contains an equivalent degree of compliance and control.

(r) Overlap of subpart CC with other regulations for gasoline loading racks. After the compliance dates specified in paragraph (h) of this section, a Group 1 gasoline loading rack that is part of a source subject to subpart CC and also is subject to the provisions of 40 CFR part 60, subpart XX is required to comply only with this subpart.

(s) Overlap of this subpart with other regulation for flares. On January 30, 2019, flares that are subject to the provisions of 40 CFR 60.18 or 63.11 and subject to this subpart are required to comply only with the provisions specified in this subpart. Prior to January 30, 2019, flares that are subject to the provisions of 40 CFR 60.18 or 63.11 and elect to comply with the requirements in §§63.670 and 63.671 are required to comply only with the provisions specified in this subpart.

[60 FR 43260, Aug. 18, 1995; 61 FR 7051, Feb. 23, 1996, as amended at 61 FR 29878, June 12, 1996; 63 FR 44140, Aug. 18, 1998; 66 FR 28841, May 25, 2001; 74 FR 55683, Oct. 28, 2009; 78 FR 37145, June 20, 2013; 80 FR 75237, Dec. 1, 2015]

§63.641 Definitions.

All terms used in this subpart shall have the meaning given them in the Clean Air Act, subpart A of this part, and in this section. If the same term is defined in subpart A and in this section, it shall have the meaning given in this section for purposes of this subpart.

Affected source means the collection of emission points to which this subpart applies as determined by the criteria in §63.640.

Aliphatic means open-chained structure consisting of paraffin, olefin and acetylene hydrocarbons and derivatives.

Annual average true vapor pressure means the equilibrium partial pressure exerted by the stored liquid at the temperature equal to the annual average of the liquid storage temperature for liquids stored above or below the ambient temperature or at the local annual average temperature reported by the National Weather Service for liquids stored at the ambient temperature, as determined:

(1) In accordance with methods specified in §63.111 of subpart G of this part;

(2) From standard reference texts; or

(3) By any other method approved by the Administrator.

Assist air means all air that intentionally is introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame. *Assist air* includes premix assist air and perimeter assist air. *Assist air* does not include the surrounding ambient air.

Assist steam means all steam that intentionally is introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame. *Assist steam* includes, but is not necessarily limited to, center steam, lower steam and upper steam.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator.

By compound means by individual stream components, not by carbon equivalents.

Car-seal means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Center steam means the portion of assist steam introduced into the stack of a flare to reduce burnback.

Closed blowdown system means a system used for depressuring process vessels that is not open to the atmosphere and is configured of piping, ductwork, connections, accumulators/knockout drums, and, if necessary, flow inducing devices that transport gas or vapor from a process vessel to a control device or back into the process.

Closed vent system means a system that is not open to the atmosphere and is configured of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission point to a control device or back into the process. If gas or vapor from regulated equipment is routed to a process (e.g., to a petroleum refinery fuel gas system), the process shall not be considered a closed vent system and is not subject to closed vent system standards.

Combustion device means an individual unit of equipment such as a flare, incinerator, process heater, or boiler used for the combustion of organic hazardous air pollutant vapors.

Combustion zone means the area of the flare flame where the combustion zone gas combines for combustion.

Combustion zone gas means all gases and vapors found just after a flare tip. This gas includes all flare vent gas, total steam, and premix air.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation. For the purpose of reporting and recordkeeping, connector means joined fittings that are accessible.

Continuous record means documentation, either in hard copy or computer readable form, of data values measured at least once every hour and recorded at the frequency specified in §63.655(i).

Continuous recorder means a data recording device recording an instantaneous data value or an average data value at least once every hour.

Control device means any equipment used for recovering, removing, or oxidizing organic hazardous air pollutants. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, incinerators, flares, boilers, and process heaters. For miscellaneous process vents (as defined in this section), recovery devices (as defined in this section) are not considered control devices.

Cooling tower means a heat removal device used to remove the heat absorbed in circulating cooling water systems by transferring the heat to the atmosphere using natural or mechanical draft.

Cooling tower return line means the main water trunk lines at the inlet to the cooling tower before exposure to the atmosphere.

Decoking operations means the sequence of steps conducted at the end of the delayed coking unit's cooling cycle to open the coke drum to the atmosphere in order to remove coke from the coke drum. *Decoking operations* begin at the end of the cooling cycle when steam released from the coke drum is no longer discharged via the unit's blowdown system but instead is vented directly to the atmosphere. *Decoking operations* include atmospheric depressuring (venting), deheading, draining, and decoking (coke cutting).

Delayed coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A *delayed coking unit* includes, but is not limited to, all of the coke drums associated with a single fractionator; the fractionator, including the bottoms receiver and the overhead condenser; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; and the coke drum blowdown recovery compressor system.

Delayed coker vent means a miscellaneous process vent that contains uncondensed vapors from the delayed coking unit's blowdown system. Venting from the *delayed coker vent* is typically intermittent in nature, and occurs primarily during the cooling cycle of a delayed coking unit coke drum when vapor from the coke drums cannot be sent to the fractionator column for product recovery. The emissions from the decoking operations, which include direct atmospheric venting, deheading, draining, or decoking (coke cutting), are not considered to be *delayed coker vents*.

Distillate receiver means overhead receivers, overhead accumulators, reflux drums, and condenser(s) including ejector-condenser(s) associated with a distillation unit.

Distillation unit means a device or vessel in which one or more feed streams are separated into two or more exit streams, each exit stream having component concentrations different from those in the feed stream(s). The separation is achieved by the redistribution of the components between the liquid and the vapor phases by vaporization and condensation as they approach equilibrium within the distillation unit. Distillation unit includes the distillate receiver, reboiler, and any associated vacuum pump or steam jet.

Emission point means an individual miscellaneous process vent, storage vessel, wastewater stream, equipment leak, decoking operation or heat exchange system associated with a petroleum refining process unit; an individual storage vessel or equipment leak associated with a bulk gasoline terminal or pipeline breakout station classified under Standard Industrial Classification code 2911; a gasoline loading rack classified under Standard Industrial Classification code 2911; or a marine tank vessel loading operation located at a petroleum refinery.

Equipment leak means emissions of organic hazardous air pollutants from a pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system “in organic hazardous air pollutant service” as defined in this section. Vents from wastewater collection and conveyance systems (including, but not limited to wastewater drains, sewer vents, and sump drains), tank mixers, and sample valves on storage tanks are not equipment leaks.

Flame zone means the portion of a combustion chamber of a boiler or process heater occupied by the flame envelope created by the primary fuel.

Flare means a combustion device lacking an enclosed combustion chamber that uses an uncontrolled volume of ambient air to burn gases. For the purposes of this rule, the definition of *flare* includes, but is not necessarily limited to, air-assisted flares, steam-assisted flares and non-assisted flares.

Flare purge gas means gas introduced between a flare header's water seal and the flare tip to prevent oxygen infiltration (backflow) into the flare tip. For a flare with no water seal, the function of *flare purge gas* is performed by flare sweep gas and, therefore, by definition, such a flare has no *flare purge gas*.

Flare supplemental gas means all gas introduced to the flare in order to improve the combustible characteristics of combustion zone gas.

Flare sweep gas means, for a flare with a flare gas recovery system, the gas intentionally introduced into the flare header system to maintain a constant flow of gas through the flare header in order to prevent oxygen buildup in the flare header; *flare sweep gas* in these flares is introduced prior to and recovered by the flare gas recovery system. For a flare without a flare gas recovery system, *flare sweep gas* means the gas intentionally introduced into the flare header system to maintain a constant flow of gas through the flare header and out the flare tip in order to prevent oxygen buildup in the flare header and to prevent oxygen infiltration (backflow) into the flare tip.

Flare vent gas means all gas found just prior to the flare tip. This gas includes all flare waste gas (*i.e.*, gas from facility operations that is directed to a flare for the purpose of disposing of the gas), that portion of flare sweep gas that is not recovered, flare purge gas and flare supplemental gas, but does not include pilot gas, total steam or assist air.

Flexible enclosure device means a seal made of an elastomeric fabric (or other material) which completely encloses a slotted guidepole or ladder and eliminates the vapor emission pathway from inside the storage vessel through the guidepole slots or ladder slots to the outside air.

Flexible operation unit means a process unit that manufactures different products periodically by alternating raw materials or operating conditions. These units are also referred to as campaign plants or blocked operations.

Flow indicator means a device that indicates whether gas is flowing, or whether the valve position would allow gas to flow, in a line.

Force majeure event means a release of HAP, either directly to the atmosphere from a pressure relief device or discharged via a flare, that is demonstrated to the satisfaction of the Administrator to result from an event beyond the refinery owner or operator's control, such as natural disasters; acts of war or terrorism; loss of a utility external to the refinery (*e.g.,* external power curtailment), excluding power curtailment due to an interruptible service agreement; and fire or explosion originating at a near or adjoining facility outside of the refinery that impacts the refinery's ability to operate.

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous streams generated by refinery operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric. The gaseous streams can contain a mixture of methane, light hydrocarbons, hydrogen and other miscellaneous species.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater that is used as a fuel for internal combustion engines.

Gasoline loading rack means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill gasoline cargo tanks.

Group 1 gasoline loading rack means any gasoline loading rack classified under Standard Industrial Classification code 2911 that is located within a bulk gasoline terminal that has a gasoline throughput greater than 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput for the terminal as may be limited by compliance with enforceable conditions under Federal, State, or local law and discovered by the Administrator and any other person.

Group 1 marine tank vessel means a vessel at an existing source loaded at any land- or sea-based terminal or structure that loads liquid commodities with vapor pressures greater than or equal to 10.3 kilopascals in bulk onto marine tank vessels, that emits greater than 9.1 megagrams of any individual HAP or 22.7 megagrams of any combination of HAP annually after August 18, 1999, or a vessel at a new source loaded at any land- or sea-based terminal or structure that loads liquid commodities with vapor pressures greater than or equal to 10.3 kilopascals onto marine tank vessels.

Group 1 miscellaneous process vent means a miscellaneous process vent for which the total organic HAP concentration is greater than or equal to 20 parts per million by volume, and the total volatile organic compound emissions are greater than or equal to 33 kilograms per day for existing sources and 6.8 kilograms per day for new sources at the outlet of the final recovery device (if any) and prior to any control device and prior to discharge to the atmosphere.

Group 1 storage vessel means:

(1) Prior to February 1, 2016:

(i) A storage vessel at an existing source that has a design capacity greater than or equal to 177 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 10.4 kilopascals and stored-liquid annual average true vapor pressure greater than or equal to 8.3 kilopascals and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP;

(ii) A storage vessel at a new source that has a design storage capacity greater than or equal to 151 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 3.4 kilopascals and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP; or

(iii) A storage vessel at a new source that has a design storage capacity greater than or equal to 76 cubic meters and less than 151 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 77 kilopascals and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP.

(2) On and after February 1, 2016:

(i) A storage vessel at an existing source that has a design capacity greater than or equal to 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 5.2 kilopascals (0.75 pounds per square inch) and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP;

(ii) A storage vessel at an existing source that has a design storage capacity greater than or equal to 76 cubic meters (20,000 gallons) and less than 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 13.1 kilopascals (1.9 pounds per square inch) and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP;

(iii) A storage vessel at a new source that has a design storage capacity greater than or equal to 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 3.4 kilopascals (0.5 pounds per square inch) and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP; or

(iv) A storage vessel at a new source that has a design storage capacity greater than or equal to 76 cubic meters (20,000 gallons) and less than 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 13.1 kilopascals (1.9 pounds per square inch) and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP.

Group 1 wastewater stream means a wastewater stream at a petroleum refinery with a total annual benzene loading of 10 megagrams per year or greater as calculated according to the procedures in 40 CFR 61.342 of subpart FF of part 61 that has a flow rate of 0.02 liters per minute or greater, a benzene concentration of 10 parts per million by weight or greater, and is not exempt from control requirements under the provisions of 40 CFR part 61, subpart FF.

Group 2 gasoline loading rack means a gasoline loading rack classified under Standard Industrial Classification code 2911 that does not meet the definition of a Group 1 gasoline loading rack.

Group 2 marine tank vessel means a marine tank vessel that does not meet the definition of a Group 1 marine tank vessel.

Group 2 miscellaneous process vent means a miscellaneous process vent that does not meet the definition of a Group 1 miscellaneous process vent.

Group 2 storage vessel means a storage vessel that does not meet the definition of a Group 1 storage vessel.

Group 2 wastewater stream means a wastewater stream that does not meet the definition of Group 1 wastewater stream.

Hazardous air pollutant or *HAP* means one of the chemicals listed in section 112(b) of the Clean Air Act.

Heat exchange system means a device or collection of devices used to transfer heat from process fluids to water without intentional direct contact of the process fluid with the water (*i.e.,* non-contact heat exchanger) and to transport and/or cool the water in a closed-loop recirculation system (cooling tower system) or a once-through system (e.g., river or pond water). For closed-loop recirculation systems, the *heat exchange system* consists of a cooling tower, all petroleum refinery process unit heat exchangers that are in organic HAP service, as defined in this subpart, serviced by that cooling tower, and all water lines to and from these petroleum refinery process unit heat exchangers. For once-through systems, the *heat exchange system* consists of all heat exchangers that are in organic HAP service, as defined in this subpart, servicing an individual petroleum refinery process unit and all water lines to and from these heat exchangers. Sample coolers or pump seal coolers are not considered heat exchangers for the purpose of this definition and are not part of the *heat exchange system.* Intentional direct contact with process fluids results in the formation of a wastewater.

Heat exchanger exit line means the cooling water line from the exit of one or more heat exchangers (where cooling water leaves the heat exchangers) to either the entrance of the cooling tower return line or prior to exposure to the atmosphere, in, as an example, a once-through cooling system, whichever occurs first.

Incinerator means an enclosed combustion device that is used for destroying organic compounds. Auxiliary fuel may be used to heat waste gas to combustion temperatures. Any energy recovery section present is not physically formed into one manufactured or assembled unit with the combustion section; rather, the energy recovery section is a separate section following the combustion section and the two are joined by ducts or connections carrying flue gas.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.593(d) of part 60, subpart GGG.

In organic hazardous air pollutant service or *in organic HAP service* means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP as determined according to the provisions of §63.180(d) of this part and table 1 of this subpart. The provisions of §63.180(d) also specify how to determine that a piece of equipment is not in organic HAP service.

Leakless valve means a valve that has no external actuating mechanism.

Lower steam means the portion of assist steam piped to an exterior annular ring near the lower part of a flare tip, which then flows through tubes to the flare tip, and ultimately exits the tubes at the flare tip.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the stored liquid at the temperature equal to the highest calendar-month average of the liquid storage temperature for liquids stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for liquids stored at the ambient temperature, as determined:

(1) In accordance with methods specified in §63.111 of subpart G of this part;

(2) From standard reference texts; or

(3) By any other method approved by the Administrator.

Miscellaneous process vent means a gas stream containing greater than 20 parts per million by volume organic HAP that is continuously or periodically discharged from a petroleum refining process unit meeting the criteria specified in §63.640(a). *Miscellaneous process vents* include gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device prior to control or discharge to the atmosphere. *Miscellaneous process vents* include vent streams from: Caustic wash accumulators, distillation tower condensers/accumulators, flash/knockout drums, reactor vessels, scrubber overheads, stripper overheads, vacuum pumps, steam ejectors, hot wells, high point bleeds, wash tower overheads, water wash accumulators, blowdown condensers/accumulators, and delayed coker vents. *Miscellaneous process vents* do not include:

(1) Gaseous streams routed to a fuel gas system, provided that on and after January 30, 2019, any flares receiving gas from the fuel gas system are in compliance with §63.670;

(2) Pressure relief device discharges;

(3) Leaks from equipment regulated under §63.648;

(4) [Reserved]

(5) In situ sampling systems (onstream analyzers) until February 1, 2016. After this date, these sampling systems will be included in the definition of miscellaneous process vents and sampling systems determined to be Group 1 miscellaneous process vents must comply with the requirements in §§63.643 and 63.644 no later than January 30, 2019;

(6) Catalytic cracking unit catalyst regeneration vents;

(7) Catalytic reformer regeneration vents;

(8) Sulfur plant vents;

(9) Vents from control devices such as scrubbers, boilers, incinerators, and electrostatic precipitators applied to catalytic cracking unit catalyst regeneration vents, catalytic reformer regeneration vents, and sulfur plant vents;

(10) Vents from any stripping operations applied to comply with the wastewater provisions of this subpart, subpart G of this part, or 40 CFR part 61, subpart FF;

(11) Emissions associated with delayed coking unit decoking operations;

(12) Vents from storage vessels;

(13) Emissions from wastewater collection and conveyance systems including, but not limited to, wastewater drains, sewer vents, and sump drains; and

(14) Hydrogen production plant vents through which carbon dioxide is removed from process streams or through which steam condensate produced or treated within the hydrogen plant is degassed or deaerated.

Net heating value means the energy released as heat when a compound undergoes complete combustion with oxygen to form gaseous carbon dioxide and gaseous water (also referred to as lower heating value).

Operating permit means a permit required by 40 CFR parts 70 or 71.

Organic hazardous air pollutant or *organic HAP* in this subpart, means any of the organic chemicals listed in table 1 of this subpart.

Perimeter assist air means the portion of assist air introduced at the perimeter of the flare tip or above the flare tip. *Perimeter assist air* includes air intentionally entrained in lower and upper steam. *Perimeter assist air* includes all assist air except premix assist air.

Periodically discharged means discharges that are intermittent and associated with routine operations, maintenance activities, startups, shutdowns, malfunctions, or process upsets.

Petroleum-based solvents means mixtures of aliphatic hydrocarbons or mixtures of one and two ring aromatic hydrocarbons.

Petroleum refining process unit means a process unit used in an establishment primarily engaged in petroleum refining as defined in the Standard Industrial Classification code for petroleum refining (2911), and used primarily for the following:

(1) Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants;

(2) Separating petroleum; or

(3) Separating, cracking, reacting, or reforming intermediate petroleum streams.

(4) Examples of such units include, but are not limited to, petroleum-based solvent units, alkylation units, catalytic hydrotreating, catalytic hydrorefining, catalytic hydrocracking, catalytic reforming, catalytic cracking, crude distillation, lube oil processing, hydrogen production, isomerization, polymerization, thermal processes, and blending, sweetening, and treating processes. Petroleum refining process units also include sulfur plants.

Pilot gas means gas introduced into a flare tip that provides a flame to ignite the flare vent gas.

Plant site means all contiguous or adjoining property that is under common control including properties that are separated only by a road or other public right-of-way. Common control includes properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, or any combination thereof.

Premix assist air means the portion of assist air that is introduced to the flare vent gas, whether injected or induced, prior to the flare tip. Premix assist air also includes any air intentionally entrained in center steam.

Primary fuel means the fuel that provides the principal heat input (i.e., more than 50 percent) to the device. To be considered primary, the fuel must be able to sustain operation without the addition of other fuels.

Process heater means an enclosed combustion device that primarily transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water.

Process unit means the equipment assembled and connected by pipes or ducts to process raw and/or intermediate materials and to manufacture an intended product. A process unit includes any associated storage vessels. For the purpose of this subpart, process unit includes, but is not limited to, chemical manufacturing process units and petroleum refining process units.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours is not considered a process unit shutdown. An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, or would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown is not considered a process unit shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not considered process unit shutdowns.

Recovery device means an individual unit of equipment capable of and used for the purpose of recovering chemicals for use, reuse, or sale. Recovery devices include, but are not limited to, absorbers, carbon adsorbers, and condensers.

Reference control technology for gasoline loading racks means a vapor collection and processing system used to reduce emissions due to the loading of gasoline cargo tanks to 10 milligrams of total organic compounds per liter of gasoline loaded or less.

Reference control technology for marine vessels means a vapor collection system and a control device that reduces captured HAP emissions by 97 percent.

Reference control technology for miscellaneous process vents means a combustion device used to reduce organic HAP emissions by 98 percent, or to an outlet concentration of 20 parts per million by volume.

Reference control technology for storage vessels means either:

(1) For Group 1 storage vessels complying with §63.660:

(i) An internal floating roof, including an external floating roof converted to an internal floating roof, meeting the specifications of §63.1063(a)(1)(i) and (b);

(ii) An external floating roof meeting the specifications of §63.1063(a)(1)(ii), (a)(2), and (b); or

(iii) [Reserved]

(iv) A closed-vent system to a control device that reduces organic HAP emissions by 95 percent, or to an outlet concentration of 20 parts per million by volume (ppmv).

(v) For purposes of emissions averaging, these four technologies are considered equivalent.

(2) For all other storage vessels:

(i) An internal floating roof meeting the specifications of §63.119(b) of subpart G except for §63.119(b)(5) and (6);

(ii) An external floating roof meeting the specifications of §63.119(c) of subpart G except for §63.119(c)(2);

(iii) An external floating roof converted to an internal floating roof meeting the specifications of §63.119(d) of subpart G except for §63.119(d)(2); or

(iv) A closed-vent system to a control device that reduces organic HAP emissions by 95 percent, or to an outlet concentration of 20 parts per million by volume.

(v) For purposes of emissions averaging, these four technologies are considered equivalent.

Reference control technology for wastewater means the use of:

(1) Controls specified in §§61.343 through 61.347 of subpart FF of part 61;

(2) A treatment process that achieves the emission reductions specified in table 7 of this subpart for each individual HAP present in the wastewater stream or is a steam stripper that meets the specifications in §63.138(g) of subpart G of this part; and

(3) A control device to reduce by 95 percent (or to an outlet concentration of 20 parts per million by volume for combustion devices) the organic HAP emissions in the vapor streams vented from treatment processes (including the steam stripper described in paragraph (2) of this definition) managing wastewater.

Refinery fuel gas means a gaseous mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species (nitrogen, carbon dioxide, hydrogen sulfide, etc.) that is produced in the refining of crude oil and/or petrochemical processes and that is separated for use as a fuel in boilers and process heaters throughout the refinery.

Regulated material means any stream associated with emission sources listed in §63.640(c) required to meet control requirements under this subpart as well as any stream for which this subpart or a cross-referencing subpart specifies that the requirements for flare control devices in §63.670 must be met.

Relief valve means a valve used only to release an unplanned, nonroutine discharge. A relief valve discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.

Research and development facility means laboratory and pilot plant operations whose primary purpose is to conduct research and development into new processes and products, where the operations are under the close supervision of technically trained personnel, and is not engaged in the manufacture of products for commercial sale, except in a de minimis manner.

Shutdown means the cessation of a petroleum refining process unit or a unit operation (including, but not limited to, a distillation unit or reactor) within a petroleum refining process unit for purposes including, but not limited to, periodic maintenance, replacement of equipment, or repair.

Startup means the setting into operation of a petroleum refining process unit for purposes of production. Startup does not include operation solely for purposes of testing equipment. Startup does not include changes in product for flexible operation units.

Storage vessel means a tank or other vessel that is used to store organic liquids. Storage vessel does not include:

(1) Vessels permanently attached to motor vehicles such as trucks, railcars, barges, or ships;

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

(3) Vessels with capacities smaller than 40 cubic meters;

(4) Bottoms receiver tanks; or

(5) Wastewater storage tanks. Wastewater storage tanks are covered under the wastewater provisions.

Temperature monitoring device means a unit of equipment used to monitor temperature and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater.

Thermal expansion relief valve means a pressure relief valve designed to protect equipment from excess pressure due to thermal expansion of blocked liquid-filled equipment or piping due to ambient heating or heat from a heat tracing system. Pressure relief valves designed to protect equipment from excess pressure due to blockage against a pump or compressor or due to fire contingency are not thermal expansion relief valves.

Total annual benzene means the total amount of benzene in waste streams at a facility on an annual basis as determined in §61.342 of 40 CFR part 61, subpart FF.

Total organic compounds or *TOC,* as used in this subpart, means those compounds excluding methane and ethane measured according to the procedures of Method 18 of 40 CFR part 60, appendix A. Method 25A may be used alone or in combination with Method 18 to measure TOC as provided in §63.645 of this subpart.

Total steam means the total of all steam that is supplied to a flare and includes, but is not limited to, lower steam, center steam and upper steam.

Upper steam means the portion of assist steam introduced via nozzles located on the exterior perimeter of the upper end of the flare tip.

Wastewater means water or wastewater that, during production or processing, comes into direct contact with or results from the production or use of any raw material, intermediate product, finished product, byproduct, or waste product and is discharged into any individual drain system. Examples are feed tank drawdown; water formed during a chemical reaction or used as a reactant; water used to wash impurities from organic products or reactants; water used to cool or quench organic vapor streams through direct contact; and condensed steam from jet ejector systems pulling vacuum on vessels containing organics.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29879, June 12, 1996; 62 FR 7938, Feb. 21, 1997; 63 FR 31361, June 9, 1998; 63 FR 44141, Aug. 18, 1998; 74 FR 55685, Oct. 28, 2008; 78 FR 37146, June 20, 2013; 80 FR 75239, Dec. 1, 2015; 81 FR 45241, July 13, 2016]

§63.642 General standards.

(a) Each owner or operator of a source subject to this subpart is required to apply for a part 70 or part 71 operating permit from the appropriate permitting authority. If the EPA has approved a State operating permit program under part 70, the permit shall be obtained from the State authority. If the State operating permit program has not been approved, the source shall apply to the EPA Regional Office pursuant to part 71.

(b) The emission standards set forth in this subpart shall apply at all times.

(c) Table 6 of this subpart specifies the provisions of subpart A of this part that apply and those that do not apply to owners and operators of sources subject to this subpart.

(d) Initial performance tests and initial compliance determinations shall be required only as specified in this subpart.

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

(2) The owner or operator 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 §63.7(e) except that performance tests shall be conducted at maximum representative operating capacity for the process. During the performance test, an owner or operator shall operate the control device at either maximum or minimum representative operating conditions for monitored control device parameters, whichever results in lower emission reduction. An owner or operator shall not conduct a performance test during startup, shutdown, periods when the control device is bypassed or periods when the process, monitoring equipment or control device is not operating properly. The owner/operator may not conduct performance tests during periods of malfunction. The owner or operator must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that the test was conducted at maximum representative operating capacity. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(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.

(e) All applicable records shall be maintained as specified in §63.655(i).

(f) All reports required under this subpart shall be sent to the Administrator at the addresses listed in §63.13 of subpart A of this part. If acceptable to both the Administrator and the owner or operator of a source, reports may be submitted on electronic media.

(g) The owner or operator of an existing source subject to the requirements of this subpart shall control emissions of organic HAP's to the level represented by the following equation:

$$E_A = 0.02\Sigma\ EPV_1 + \Sigma\ EPV_2 + 0.05\Sigma\ ES_1 + \Sigma\ ES_2 + \Sigma\ EGLR_{1C} + \Sigma\ EGLR_2 + (R)\ \Sigma\ EMV_1 + \Sigma\ EMV_2 + \Sigma\ EWW_{1C} + \Sigma\ EWW_2$$

where:

E_A = Emission rate, megagrams per year, allowed for the source.

$0.02\Sigma\ EPV_1$ = Sum of the residual emissions, megagrams per year, from all Group 1 miscellaneous process vents, as defined in §63.641.

$\Sigma\ EPV_2$ = Sum of the emissions, megagrams per year, from all Group 2 process vents, as defined in §63.641.

$0.05\Sigma\ ES_1$ = Sum of the residual emissions, megagrams per year, from all Group 1 storage vessels, as defined in §63.641.

$\Sigma\ ES_2$ = Sum of the emissions, megagrams per year, from all Group 2 storage vessels, as defined in §63.641.

$\Sigma\ EGLR_{1C}$ = Sum of the residual emissions, megagrams per year, from all Group 1 gasoline loading racks, as defined in §63.641.

$\Sigma\ EGLR_2$ = Sum of the emissions, megagrams per year, from all Group 2 gasoline loading racks, as defined in §63.641.

$(R)\Sigma\ EMV_1$ = Sum of the residual emissions megagrams per year, from all Group 1 marine tank vessels, as defined in §63.641.

R = 0.03 for existing sources, 0.02 for new sources.

$\Sigma\ EMV_2$ = Sum of the emissions, megagrams per year from all Group 2 marine tank vessels, as defined in §63.641.

$\Sigma\ EWW_{1C}$ = Sum of the residual emissions from all Group 1 wastewater streams, as defined in §63.641. This term is calculated for each Group 1 stream according to the equation for EWW_{ic} in §63.652(h)(6).

$\Sigma\ EWW_2$ = Sum of emissions from all Group 2 wastewater streams, as defined in §63.641.

The emissions level represented by this equation is dependent on the collection of emission points in the source. The level is not fixed and can change as the emissions from each emission point change or as the number of emission points in the source changes.

(h) The owner or operator of a new source subject to the requirements of this subpart shall control emissions of organic HAP's to the level represented by the equation in paragraph (g) of this section.

(i) The owner or operator of an existing source shall demonstrate compliance with the emission standard in paragraph (g) of this section by following the procedures specified in paragraph (k) of this section for all emission points, or by following the emissions averaging compliance approach specified in paragraph (l) of this section for specified emission points and the procedures specified in paragraph (k)(1) of this section.

(j) The owner or operator of a new source shall demonstrate compliance with the emission standard in paragraph (h) of this section only by following the procedures in paragraph (k) of this section. The owner or operator of a new source may not use the emissions averaging compliance approach.

(k) The owner or operator of an existing source may comply, and the owner or operator of a new source shall comply, with the applicable provisions in §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as specified in §63.640(h).

(1) The owner or operator using this compliance approach shall also comply with the requirements of §§63.648 and/or 63.649, 63.654, 63.655, 63.657, 63.658, 63.670 and 63.671, as applicable.

(2) The owner or operator using this compliance approach is not required to calculate the annual emission rate specified in paragraph (g) of this section.

(l) The owner or operator of an existing source may elect to control some of the emission points within the source to different levels than specified under §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable according to §63.640(h), by using an emissions averaging compliance approach as long as the overall emissions for the source do not exceed the emission level specified in paragraph (g) of this section. The owner or operator using emissions averaging shall meet the requirements in paragraphs (l)(1) and (2) of this section.

(1) Calculate emission debits and credits for those emission points involved in the emissions average according to the procedures specified in §63.652; and

(2) Comply with the requirements of §§63.648 and/or 63.649, 63.654, 63.652, 63.653, 63.655, 63.657, 63.658, 63.670 and 63.671, as applicable.

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

(n) At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[60 FR 43260, Aug. 18, 1995; 61 FR 7051, Feb. 23, 1996, as amended at 61 FR 29879, June 12, 1996; 74 FR 55685, Oct. 28, 2009; 80 FR 75242, Dec. 1, 2015]

§63.643 Miscellaneous process vent provisions.

(a) The owner or operator of a Group 1 miscellaneous process vent as defined in §63.641 shall comply with the requirements of either paragraph (a)(1) or (2) of this section or, if applicable, paragraph (c) of this section. The owner or operator of a miscellaneous process vent that meets the conditions in paragraph (c) of this section is only required to comply with the requirements of paragraph (c) of this section and §63.655(g)(13) and (i)(12) for that vent.

(1) Reduce emissions of organic HAP's using a flare. On and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the requirements of §63.11(b) of subpart A or the requirements of §63.670.

(2) Reduce emissions of organic HAP's, using a control device, by 98 weight-percent or to a concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent. Compliance can be determined by measuring either organic HAP's or TOC's using the procedures in §63.645.

(b) If a boiler or process heater is used to comply with the percentage of reduction requirement or concentration limit specified in paragraph (a)(2) of this section, then the vent stream shall be introduced into the flame zone of such a device, or in a location such that the required percent reduction or concentration is achieved. Testing and monitoring is required only as specified in §§63.644(a) and 63.645 of this subpart.

(c) An owner or operator may designate a process vent as a maintenance vent if the vent is only used as a result of startup, shutdown, maintenance, or inspection of equipment where equipment is emptied, depressurized, degassed or placed into service. The owner or operator does not need to designate a maintenance vent as a Group 1 or Group 2 miscellaneous process vent. The owner of operator must comply with the applicable requirements in paragraphs (c)(1) through (3) of this section for each maintenance vent according to the compliance dates specified in table 11 of this subpart, unless an extension is requested in accordance with the provisions in §63.6(i).

(1) Prior to venting to the atmosphere, process liquids are removed from the equipment as much as practical and the equipment is depressured to a control device, fuel gas system, or back to the process until one of the following conditions, as applicable, is met.

(i) The vapor in the equipment served by the maintenance vent has a lower explosive limit (LEL) of less than 10 percent.

(ii) If there is no ability to measure the LEL of the vapor in the equipment based on the design of the equipment, the pressure in the equipment served by the maintenance vent is reduced to 5 psig or less. Upon opening the maintenance vent, active purging of the equipment cannot be used until the LEL of the vapors in the maintenance vent (or inside the equipment if the maintenance is a hatch or similar type of opening) equipment is less than 10 percent.

(iii) The equipment served by the maintenance vent contains less than 72 pounds of VOC.

(iv) If the maintenance vent is associated with equipment containing pyrophoric catalyst (*e.g.*, hydrotreaters and hydrocrackers) at refineries that do not have a pure hydrogen supply, the LEL of the vapor in the equipment must be less than 20 percent, except for one event per year not to exceed 35 percent.

(2) Except for maintenance vents complying with the alternative in paragraph (c)(1)(iii) of this section, the owner or operator must determine the LEL or, if applicable, equipment pressure using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications.

(3) For maintenance vents complying with the alternative in paragraph (c)(1)(iii) of this section, the owner or operator shall determine mass of VOC in the equipment served by the maintenance vent based on the equipment size and contents after considering any contents drained or purged from the equipment. Equipment size may be determined from equipment design specifications. Equipment contents may be determined using process knowledge.

(d) After February 1, 2016 and prior to the date of compliance with the maintenance vent provisions in paragraph (c) of this section, the owner or operator must comply with the requirements in §63.642(n) for each maintenance venting event and maintain records necessary to demonstrate compliance with the requirements in §63.642(n) including, if appropriate, records of existing standard site procedures used to deinventory equipment for safety purposes.

[60 FR 43260, Aug. 18, 1995, as amended at 80 FR 75242, Dec. 1, 2015; 81 FR 45241, July 13, 2016]

§63.644 Monitoring provisions for miscellaneous process vents.

(a) Except as provided in paragraph (b) of this section, each owner or operator of a Group 1 miscellaneous process vent that uses a combustion device to comply with the requirements in §63.643(a) shall install the monitoring equipment specified in paragraph (a)(1), (2), (3), or (4) of this section, depending on the type of combustion device used. All monitoring equipment shall be installed, calibrated, maintained, and operated according to manufacturer's specifications or other written procedures that provide adequate assurance that the equipment will monitor accurately and, except for CPMS installed for pilot flame monitoring, must meet the applicable minimum accuracy, calibration and quality control requirements specified in table 13 of this subpart.

(1) Where an incinerator is used, a temperature monitoring device equipped with a continuous recorder is required.

(i) Where an incinerator other than a catalytic incinerator is used, a temperature monitoring device shall be installed in the firebox or in the ductwork immediately downstream of the firebox in a position before any substantial heat exchange occurs.

(ii) Where a catalytic incinerator is used, temperature monitoring devices shall be installed in the gas stream immediately before and after the catalyst bed.

(2) Where a flare is used prior to January 30, 2019, a device (including but not limited to a thermocouple, an ultraviolet beam sensor, or an infrared sensor) capable of continuously detecting the presence of a pilot flame is required, or the requirements of §63.670 shall be met. Where a flare is used on and after January 30, 2019, the requirements of §63.670 shall be met.

(3) Any boiler or process heater with a design heat input capacity greater than or equal to 44 megawatt or any boiler or process heater in which all vent streams are introduced into the flame zone is exempt from monitoring.

(4) Any boiler or process heater less than 44 megawatts design heat capacity where the vent stream is not introduced into the flame zone is required to use a temperature monitoring device in the firebox equipped with a continuous recorder.

(b) An owner or operator of a Group 1 miscellaneous process vent may request approval to monitor parameters other than those listed in paragraph (a) of this section. The request shall be submitted according to the procedures specified in §63.655(h). Approval shall be requested if the owner or operator:

(1) Uses a control device other than an incinerator, boiler, process heater, or flare; or

(2) Uses one of the control devices listed in paragraph (a) of this section, but seeks to monitor a parameter other than those specified in paragraph (a) of this section.

(c) The owner or operator of a Group 1 miscellaneous process vent using a vent system that contains bypass lines that could divert a vent stream away from the control device used to comply with paragraph (a) of this section either directly to the atmosphere or to a control device that does not comply with the requirements in §63.643(a) shall comply with either paragraph (c)(1) or (2) of this section. Use of the bypass at any time to divert a Group 1 miscellaneous process vent stream to the atmosphere or to a control device that does not comply with the requirements in §63.643(a) is an emissions standards violation. Equipment such as low leg drains and equipment subject to §63.648 are not subject to this paragraph (c).

(1) Install, calibrate and maintain a flow indicator that determines whether a vent stream flow is present at least once every hour. A manual block valve equipped with a valve position indicator may be used in lieu of a flow indicator, as long as the valve position indicator is monitored continuously. Records shall be generated as specified in §63.655(h) and (i). The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere; or

(2) Secure the bypass line valve in the non-diverting position with a car-seal or a lock-and-key type configuration. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the non-diverting position and that the vent stream is not diverted through the bypass line.

(d) The owner or operator shall establish a range that ensures compliance with the emissions standard for each parameter monitored under paragraphs (a) and (b) of this section. In order to establish the range, the information required in §63.655(f)(3) shall be submitted in the Notification of Compliance Status report.

(e) Each owner or operator of a control device subject to the monitoring provisions of this section shall operate the control device in a manner consistent with the minimum and/or maximum operating parameter value or procedure required to be monitored under paragraphs (a) and (b) of this section. Operation of the control device in a manner that constitutes a period of excess emissions, as defined in §63.655(g)(6), or failure to perform procedures required by this section shall constitute a violation of the applicable emission standard of this subpart.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 63 FR 44141, Aug. 18, 1998; 74 FR 55685, Oct. 28, 2009; 80 FR 75243, Dec. 1, 2015]

§63.645 Test methods and procedures for miscellaneous process vents.

(a) To demonstrate compliance with §63.643, an owner or operator shall follow §63.116 except for §63.116 (a)(1), (d) and (e) of subpart G of this part except as provided in paragraphs (b) through (d) and paragraph (i) of this section.

(b) All references to §63.113(a)(1) or (a)(2) in §63.116 of subpart G of this part shall be replaced with §63.643(a)(1) or (a)(2), respectively.

(c) In §63.116(c)(4)(ii)(C) of subpart G of this part, organic HAP's in the list of HAP's in table 1 of this subpart shall be considered instead of the organic HAP's in table 2 of subpart F of this part.

(d) All references to §63.116(b)(1) or (b)(2) shall be replaced with paragraphs (d)(1) and (d)(2) of this section, respectively.

(1) Any boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(2) Any boiler or process heater in which all vent streams are introduced into the flame zone.

(e) For purposes of determining the TOC emission rate, as specified under paragraph (f) of this section, the sampling site shall be after the last product recovery device (as defined in §63.641 of this subpart) (if any recovery devices are present) but prior to the inlet of any control device (as defined in §63.641 of this subpart) that is present, prior to any dilution of the process vent stream, and prior to release to the atmosphere.

(1) Methods 1 or 1A of 40 CFR part 60, appendix A-1, as appropriate, shall be used for selection of the sampling site. For vents smaller than 0.10 meter in diameter, sample at the center of the vent.

(2) No traverse site selection method is needed for vents smaller than 0.10 meter in diameter.

(f) Except as provided in paragraph (g) of this section, an owner or operator seeking to demonstrate that a process vent TOC mass flow rate is less than 33 kilograms per day for an existing source or less than 6.8 kilograms per day for a new source in accordance with the Group 2 process vent definition of this subpart shall determine the TOC mass flow rate by the following procedures:

(1) The sampling site shall be selected as specified in paragraph (e) of this section.

(2) The gas volumetric flow rate shall be determined using Methods 2, 2A, 2C, 2D, or 2F of 40 CFR part 60, appendix A-1 or Method 2G of 40 CFR part 60, appendix A-2, as appropriate.

(3) Method 18 or Method 25A of 40 CFR part 60, appendix A shall be used to measure concentration; alternatively, any other method or data that has been validated according to the protocol in Method 301 of appendix A of this part may be used. If Method 25A is used, and the TOC mass flow rate calculated from the Method 25A measurement is greater than or equal to 33 kilograms per day for an existing source or 6.8 kilograms per day for a new source, Method 18 may be used to determine any non-VOC hydrocarbons that may be deducted to calculate the TOC (minus non-VOC hydrocarbons) concentration and mass flow rate. The following procedures shall be used to calculate parts per million by volume concentration:

(i) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) The TOC concentration (C_{TOC}) is the sum of the concentrations of the individual components and shall be computed for each run using the following equation if Method 18 is used:

$$C_{TOC} = \frac{\sum_{i=1}^{x}\left(\sum_{j=1}^{n} C_{ji}\right)}{X}$$

where:

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, parts per million by volume.

C_{ji} = Concentration of sample component j of the sample i, dry basis, parts per million by volume.

n = Number of components in the sample.

x = Number of samples in the sample run.

(4) The emission rate of TOC (minus methane and ethane) (E_{TOC}) shall be calculated using the following equation if Method 18 is used:

$$E = K_2\left[\sum_{j=1}^{n} C_j M_j\right] Q_s$$

where:

E = Emission rate of TOC (minus methane and ethane) in the sample, kilograms per day.

K_2 = Constant, 5.986×10^{-5} (parts per million)$^{-1}$ (gram-mole per standard cubic meter) (kilogram per gram) (minute per day), where the standard temperature (standard cubic meter) is at 20 °C.

C_j = Concentration on a dry basis of organic compound j in parts per million as measured by Method 18 of 40 CFR part 60, appendix A, as indicated in paragraph (f)(3) of this section. C_j includes all organic compounds measured minus methane and ethane.

M_j = Molecular weight of organic compound j, gram per gram-mole.

Q_s = Vent stream flow rate, dry standard cubic meters per minute, at a temperature of 20 °C.

(5) If Method 25A is used, the emission rate of TOC (E_{TOC}) shall be calculated using the following equation:

$E_{TOC} = K_2 C_{TOC} M Q_s$

where:

E_{TOC} = Emission rate of TOC (minus methane and ethane) in the sample, kilograms per day.

K_2 = Constant, 5.986×10^{-5} (parts per million) $^{-1}$ (gram-mole per standard cubic meter) (kilogram per gram)(minute per day), where the standard temperature (standard cubic meter) is at 20 °C.

C_{TOC} = Concentration of TOC on a dry basis in parts per million volume as measured by Method 25A of 40 CFR part 60, appendix A, as indicated in paragraph (f)(3) of this section.

M = Molecular weight of organic compound used to express units of C_{TOC}, gram per gram-mole.

Q_s = Vent stream flow rate, dry standard cubic meters per minute, at a temperature of 20 °C.

(g) Engineering assessment may be used to determine the TOC emission rate for the representative operating condition expected to yield the highest daily emission rate.

(1) Engineering assessment includes, but is not limited to, the following:

(i) Previous test results provided the tests are representative of current operating practices at the process unit.

(ii) Bench-scale or pilot-scale test data representative of the process under representative operating conditions.

(iii) TOC emission rate specified or implied within a permit limit applicable to the process vent.

(iv) Design analysis based on accepted chemical engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:

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

(B) Estimation of maximum flow rate based on physical equipment design such as pump or blower capacities; and

(C) Estimation of TOC concentrations based on saturation conditions.

(v) All data, assumptions, and procedures used in the engineering assessment shall be documented.

(h) The owner or operator of a Group 2 process vent shall recalculate the TOC emission rate for each process vent, as necessary, whenever process changes are made to determine whether the vent is in Group 1 or Group 2. Examples of process changes include, but are not limited to, changes in production capacity, production rate, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. For purposes of this paragraph, process changes do not include: process upsets; unintentional, temporary process changes; and changes that are within the range on which the original calculation was based.

(1) The TOC emission rate shall be recalculated based on measurements of vent stream flow rate and TOC as specified in paragraphs (e) and (f) of this section, as applicable, or on best engineering assessment of the effects of the change. Engineering assessments shall meet the specifications in paragraph (g) of this section.

(2) Where the recalculated TOC emission rate is greater than 33 kilograms per day for an existing source or greater than 6.8 kilograms per day for a new source, the owner or operator shall submit a report as specified in §63.655(f), (g), or (h) and shall comply with the appropriate provisions in §63.643 by the dates specified in §63.640.

(i) A compliance determination for visible emissions shall be conducted within 150 days of the compliance date using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 63 FR 44141, Aug. 18, 1998; 74 FR 55685, Oct. 28, 2009; 80 FR 75243, Dec. 1, 2015]

§63.646   Storage vessel provisions.

Upon a demonstration of compliance with the standards in §63.660 by the compliance dates specified in §63.640(h), the standards in this section shall no longer apply.

(a) Each owner or operator of a Group 1 storage vessel subject to this subpart shall comply with the requirements of §§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 §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 §63.641 shall apply in lieu of the Group 1 storage vessel definitions presented in tables 5 and 6 of §63.119 of subpart G of this part.

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

(2) When an owner or operator and the Administrator 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, an appropriate method (based on the type of liquid stored) as published by EPA or a consensus-based standards organization shall be used. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, *http://www.astm.org*), the American National Standards Institute (ANSI, 1819 L Street NW., 6th floor, Washington, DC 20036, (202) 293-8020, *http://www.ansi.org*), the American Gas Association (AGA, 400 North Capitol Street NW., 4th Floor, Washington, DC 20001, (202) 824-7000, *http://www.aga.org*), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, *http://www.asme.org*), the American Petroleum Institute (API, 1220 L Street NW., Washington, DC 20005-4070, (202) 682-8000, *http://www.api.org*), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356-0060, *http://www.naesb.org*).

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

(d) References shall apply as specified in paragraphs (d)(1) through (d)(10) of this section.

(1) All references to §63.100(k) of subpart F of this part (or the schedule provisions and the compliance date) shall be replaced with §63.640(h),

(2) All references to April 22, 1994 shall be replaced with August 18, 1995.

(3) All references to December 31, 1992 shall be replaced with July 15, 1994.

(4) All references to the compliance dates specified in §63.100 of subpart F shall be replaced with §63.640 (h) through (m).

(5) All references to §63.150 in §63.119 of subpart G of this part shall be replaced with §63.652.

(6) All references to §63.113(a)(2) of subpart G shall be replaced with §63.643(a)(2) of this subpart.

(7) All references to §63.126(b)(1) of subpart G shall be replaced with §63.422(b) of subpart R of this part.

(8) All references to §63.128(a) of subpart G shall be replaced with §63.425, paragraphs (a) through (c) and (e) through (h) of subpart R of this part.

(9) All references to §63.139(d)(1) in §63.120(d)(1)(ii) of subpart G are not applicable. For sources subject to this subpart, such references shall mean that 40 CFR 61.355 is applicable.

(10) All references to §63.139(c) in §63.120(d)(1)(ii) of subpart G are not applicable. For sources subject to this subpart, such references shall mean that §63.647 of this subpart is applicable.

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

(f) The following paragraphs (f)(1), (f)(2), and (f)(3) of this section apply to Group 1 storage vessels at existing sources:

(1) If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.

(2) Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting.

(3) Automatic bleeder vents 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.

(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 §§63.119 through 63.121 to §63.122(g)(1), §63.151, and references to initial notification requirements do not apply.

(i) References to the Implementation Plan in §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 §63.152(b) mean the Notification of Compliance Status required by §63.655(f).

(k) References to the Periodic Reports in §63.152(c) mean the Periodic Report required by §63.655(g).

(l) The State or local permitting authority can waive the notification requirements of §§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. The State or local permitting authority may also grant permission to refill storage vessels sooner than 30 days after submitting the notifications in §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.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 62 FR 7939, Feb. 21, 1997; 74 FR 55685, Oct. 28, 2009; 75 FR 37731, June 30, 2010; 80 FR 75243, Dec. 1, 2015]

§63.647 Wastewater provisions.

(a) Except as provided in paragraphs (b) and (c) of this section, each owner or operator of a Group 1 wastewater stream shall comply with the requirements of §§61.340 through 61.355 of this chapter for each process wastewater stream that meets the definition in §63.641.

(b) As used in this section, all terms not defined in §63.641 shall have the meaning given them in the Clean Air Act or in 40 CFR part 61, subpart FF, §61.341.

(c) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of part 61, subpart FF of this chapter, or the requirements of §63.670.

(d) Each owner or operator required under subpart FF of 40 CFR part 61 to perform periodic measurement of benzene concentration in wastewater, or to monitor process or control device operating parameters shall operate in a manner consistent with the minimum or maximum (as appropriate) permitted concentration or operating parameter values. Operation of the process, treatment unit, or control device resulting in a measured concentration or operating parameter value outside the permitted limits shall constitute a violation of the emission standards. Failure to perform required leak monitoring for closed vent systems and control devices or failure to repair leaks within the time period specified in subpart FF of 40 CFR part 61 shall constitute a violation of the standard.

[60 FR 43260, Aug. 18, 1995, as amended at 80 FR 75244, Dec. 1, 2015]

§63.648 Equipment leak standards.

(a) Each owner or operator of an existing source subject to the provisions of this subpart shall comply with the provisions of 40 CFR part 60, subpart VV, and paragraph (b) of this section except as provided in paragraphs (a)(1) and (2), (c) through (i), and (j)(1) and (2) of this section. Each owner or operator of a new source subject to the provisions of this subpart shall comply with subpart H of this part except as provided in paragraphs (c) through (i) and (j)(1) and (2) of this section.

(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 §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 owner or operator has decided, all subsequent calculations shall be on the same basis unless a permit change is made.

(3) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of part 60, subpart VV of this chapter, or the requirements of §63.670.

(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 paragraphs (b)(1) and (b)(2) of this section.

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

(2) Departures from the criteria specified in §60.485(b) of 40 CFR part 60 subpart VV or §63.180(b)(1) through (b)(5) of subpart H of this part or from the monitoring frequency specified in subpart VV or in paragraph (c) of this section (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) in this section, an owner or operator may elect to comply with the requirements of §§63.161 through 63.169, 63.171, 63.172, 63.175, 63.176, 63.177, 63.179, and 63.180 of subpart H except as provided in paragraphs (c)(1) through (12) and (e) through (i) of this section.

(1) The instrument readings that define a leak for light liquid pumps subject to §63.163 of subpart H of this part and gas/vapor and light liquid valves subject to §63.168 of subpart H of this part are specified in table 2 of this subpart.

(2) In phase III of the valve standard, the owner or operator may monitor valves for leaks as specified in paragraphs (c)(2)(i) or (c)(2)(ii) of this section.

(i) If the owner or operator does not elect to monitor connectors, then the owner or operator shall monitor valves according to the frequency specified in table 8 of this subpart.

(ii) If an owner or operator elects to monitor connectors according to the provisions of §63.649, paragraphs (b), (c), or (d), then the owner or operator shall monitor valves at the frequencies specified in table 9 of this subpart.

(3) The owner or operator shall decide no later than the first required monitoring period after the phase I compliance date specified in §63.640(h) whether to calculate the percentage leaking valves on a process unit basis or on a sourcewide basis. Once the owner or operator has decided, all subsequent calculations shall be on the same basis unless a permit change is made.

(4) The owner or operator shall decide no later than the first monitoring period after the phase III compliance date specified in §63.640(h) whether to monitor connectors according to the provisions in §63.649, paragraphs (b), (c), or (d).

(5) Connectors in gas/vapor service or light liquid service are subject to the requirements for connectors in heavy liquid service in §63.169 of subpart H of this part (except for the agitator provisions). The leak definition for valves, connectors, and instrumentation systems subject to §63.169 is 1,000 parts per million.

(6) In phase III of the pump standard, except as provided in paragraph (c)(7) of this section, owners or operators that achieve less than 10 percent of light liquid pumps leaking or three light liquid pumps leaking, whichever is greater, shall monitor light liquid pumps monthly.

(7) Owners or operators that achieve less than 3 percent of light liquid pumps leaking or one light liquid pump leaking, whichever is greater, shall monitor light liquid pumps quarterly.

(8) An owner or operator may make the election described in paragraphs (c)(3) and (c)(4) of this section at any time except that any election to change after the initial election shall be treated as a permit modification according to the terms of part 70 of this chapter.

(9) When complying with the requirements of §63.168(e)(3)(i), non-repairable valves shall be included in the calculation of percent leaking valves the first time the valve is identified as leaking and non-repairable. Otherwise, a number of non-repairable valves up to a maximum of 1 percent per year of the total number of valves in organic HAP service up to a maximum of 3 percent may be excluded from calculation of percent leaking valves for subsequent monitoring periods. When the number of non-repairable valves exceeds 3 percent of the total number of valves in organic HAP service, the number of non-repairable valves exceeding 3 percent of the total number shall be included in the calculation of percent leaking valves.

(10) If in phase III of the valve standard any valve is designated as being leakless, the owner or operator has the option of following the provisions of 40 CFR 60.482-7(f). If an owner or operator chooses to comply with the provisions of 40 CFR 60.482-7(f), the valve is exempt from the valve monitoring provisions of §63.168 of subpart H of this part.

(11) [Reserved]

(12) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of §§63.172 and 63.180, or the requirements of §63.670.

(d) Upon startup of new sources, the owner or operator shall comply with §63.163(a)(1)(ii) of subpart H of this part for light liquid pumps and §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 §63.169 of subpart H of this part.

(f) Reciprocating pumps in light liquid service are exempt from §§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 this section if an owner or operator demonstrates that a compressor is in hydrogen service.

(1) Each compressor is presumed not to be in hydrogen service unless an owner or operator 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 owner or operator shall use either:

(A) Procedures that conform to those specified in §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.

(*1*) When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, the procedures in paragraph (g)(2)(i)(A) of this section shall be used to resolve the disagreement.

(*2*) If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only by following the procedures in paragraph (g)(2)(i)(A) of this section.

(h) Each owner or operator 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.

(j) Except as specified in paragraph (j)(4) of this section, the owner or operator must comply with the requirements specified in paragraphs (j)(1) and (2) of this section for pressure relief devices, such as relief valves or rupture disks, in organic HAP gas or vapor service instead of the pressure relief device requirements of §60.482-4 or §63.165, as applicable. Except as specified in paragraphs (j)(4) and (5) of this section, the owner or operator must also comply with the requirements specified in paragraph (j)(3) of this section for all pressure relief devices.

(1) *Operating requirements.* Except during a pressure release, operate each pressure relief device in organic HAP gas or vapor service with an instrument reading of less than 500 ppm above background as detected by Method 21 of 40 CFR part 60, appendix A-7.

(2) *Pressure release requirements.* For pressure relief devices in organic HAP gas or vapor service, the owner or operator must comply with the applicable requirements in paragraphs (j)(2)(i) through (iii) of this section following a pressure release.

(i) If the pressure relief device does not consist of or include a rupture disk, conduct instrument monitoring, as specified in §60.485(b) or §63.180(c), as applicable, no later than 5 calendar days after the pressure relief device returns to organic HAP gas or vapor service following a pressure release to verify that the pressure relief device is operating with an instrument reading of less than 500 ppm.

(ii) If the pressure relief device includes a rupture disk, either comply with the requirements in paragraph (j)(2)(i) of this section (not replacing the rupture disk) or install a replacement disk as soon as practicable after a pressure release, but no later than 5 calendar days after the pressure release. The owner or operator must conduct instrument monitoring, as specified in §60.485(b) or §63.180(c), as applicable, no later than 5 calendar days after the pressure relief device returns to organic HAP gas or vapor service following a pressure release to verify that the pressure relief device is operating with an instrument reading of less than 500 ppm.

(iii) If the pressure relief device consists only of a rupture disk, install a replacement disk as soon as practicable after a pressure release, but no later than 5 calendar days after the pressure release. The owner or operator may not initiate startup of the equipment served by the rupture disk until the rupture disc is replaced. The owner or operator must conduct instrument monitoring, as specified in §60.485(b) or §63.180(c), as applicable, no later than 5 calendar days after the pressure relief device returns to organic HAP gas or vapor service following a pressure release to verify that the pressure relief device is operating with an instrument reading of less than 500 ppm.

(3) *Pressure release management.* Except as specified in paragraphs (j)(4) and (5) of this section, the owner or operator shall comply with the requirements specified in paragraphs (j)(3)(i) through (v) of this section for all pressure relief devices in organic HAP service no later than January 30, 2019.

(i) The owner or operator must equip each affected pressure relief device with a device(s) or use a monitoring system that is capable of:

(A) Identifying the pressure release;

(B) Recording the time and duration of each pressure release; and

(C) Notifying operators immediately that a pressure release is occurring. The device or monitoring system may be either specific to the pressure relief device itself or may be associated with the process system or piping, sufficient to indicate a pressure release to the atmosphere. Examples of these types of devices and systems include, but are not limited to, a rupture disk indicator, magnetic sensor, motion detector on the pressure relief valve stem, flow monitor, or pressure monitor.

(ii) The owner or operator must apply at least three redundant prevention measures to each affected pressure relief device and document these measures. Examples of prevention measures include:

(A) Flow, temperature, level and pressure indicators with deadman switches, monitors, or automatic actuators.

(B) Documented routine inspection and maintenance programs and/or operator training (maintenance programs and operator training may count as only one redundant prevention measure).

(C) Inherently safer designs or safety instrumentation systems.

(D) Deluge systems.

(E) Staged relief system where initial pressure relief valve (with lower set release pressure) discharges to a flare or other closed vent system and control device.

(iii) If any affected pressure relief device releases to atmosphere as a result of a pressure release event, the owner or operator must perform root cause analysis and corrective action analysis according to the requirement in paragraph (j)(6) of this section and implement corrective actions according to the requirements in paragraph (j)(7) of this section. The owner or operator must also calculate the quantity of organic HAP released during each pressure release event and report this quantity as required in §63.655(g)(10)(iii). Calculations may be based on data from the pressure relief device monitoring alone or in combination with process parameter monitoring data and process knowledge.

(iv) The owner or operator shall determine the total number of release events occurred during the calendar year for each affected pressure relief device separately. The owner or operator shall also determine the total number of release events for each pressure relief device for which the root cause analysis concluded that the root cause was a *force majeure*event, as defined in this subpart.

(v) Except for pressure relief devices described in paragraphs (j)(4) and (5) of this section, the following release events are a violation of the pressure release management work practice standards.

(A) Any release event for which the root cause of the event was determined to be operator error or poor maintenance.

(B) A second release event not including *force majeure* events from a single pressure relief device in a 3 calendar year period for the same root cause for the same equipment.

(C) A third release event not including *force majeure* events from a single pressure relief device in a 3 calendar year period for any reason.

(4) *Pressure relief devices routed to a control device.* If all releases and potential leaks from a pressure relief device are routed through a closed vent system to a control device, back into the process or to the fuel gas system, the owner or operator is not required to comply with paragraph (j)(1), (2), or (3) (if applicable) of this section. Both the closed vent system and control device (if applicable) must meet the requirements of §63.644. When complying with this paragraph (j)(4), all references to “Group 1 miscellaneous process vent” in §63.644 mean “pressure relief

device.” If a pressure relief device complying with this paragraph (j)(4) is routed to the fuel gas system, then on and after January 30, 2019, any flares receiving gas from that fuel gas system must be in compliance with §63.670.

(5) *Pressure relief devices exempted from pressure release management requirements.* The following types of pressure relief devices are not subject to the pressure release management requirements in paragraph (j)(3) of this section.

(i) Pressure relief devices in heavy liquid service, as defined in §63.641.

(ii) Pressure relief devices that only release material that is liquid at standard conditions (1 atmosphere and 68 degrees Fahrenheit) and that are hard-piped to a controlled drain system (*i.e.*, a drain system meeting the requirements for Group 1 wastewater streams in §63.647(a)) or piped back to the process or pipeline.

(iii) Thermal expansion relief valves.

(iv) Pressure relief devices designed with a set relief pressure of less than 2.5 psig.

(v) Pressure relief devices that do not have the potential to emit 72 lbs/day or more of VOC based on the valve diameter, the set release pressure, and the equipment contents.

(vi) Pressure relief devices on mobile equipment.

(6) *Root cause analysis and corrective action analysis.* A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a release event. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (j)(6)(i) through (iv) of this section.

(i) You may conduct a single root cause analysis and corrective action analysis for a single emergency event that causes two or more pressure relief devices installed on the same equipment to release.

(ii) You may conduct a single root cause analysis and corrective action analysis for a single emergency event that causes two or more pressure relief devices to release, regardless of the equipment served, if the root cause is reasonably expected to be a force majeure event, as defined in this subpart.

(iii) Except as provided in paragraphs (j)(6)(i) and (ii) of this section, if more than one pressure relief device has a release during the same time period, an initial root cause analysis shall be conducted separately for each pressure relief device that had a release. If the initial root cause analysis indicates that the release events have the same root cause(s), the initially separate root cause analyses may be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

(7) *Corrective action implementation.* Each owner or operator required to conduct a root cause analysis and corrective action analysis as specified in paragraphs (j)(3)(iii) and (j)(6) of this section shall implement the corrective action(s) identified in the corrective action analysis in accordance with the applicable requirements in paragraphs (j)(7)(i) through (iii) of this section.

(i) All corrective action(s) must be implemented within 45 days of the event for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that no corrective action should be implemented, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the event.

(ii) For corrective actions that cannot be fully implemented within 45 days following the event for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(iii) No later than 45 days following the event for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 63 FR 44141, Aug. 18, 1998; 80 FR 75244, Dec. 1, 2015; 81 FR 45241, July 13, 2016]

§63.649 Alternative means of emission limitation: Connectors in gas/vapor service and light liquid service.

(a) If an owner or operator elects to monitor valves according to the provisions of §63.648(c)(2)(ii), the owner or operator shall implement one of the connector monitoring programs specified in paragraphs (b), (c), or (d) of this section.

(b) *Random 200 connector alternative.* The owner or operator 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 §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 §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 paragraph (e) of this section. 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 paragraph (b)(1) of this section, the owner or operator shall conduct subsequent monitoring of connectors at the frequencies specified in paragraphs (b)(5)(i) through (b)(5)(iv) of this section.

(i) If the percentage leaking connectors is 2.0 percent or greater, the owner or operator shall survey a random sample of 200 connectors once every 6 months.

(ii) If the percentage leaking connectors is 1.0 percent or greater but less than 2.0 percent, the owner or operator shall survey a random sample of 200 connectors once per year.

(iii) If the percentage leaking connectors is 0.5 percent or greater but less than 1.0 percent, the owner or operator shall survey a random sample of 200 connectors once every 2 years.

(iv) If the percentage leaking connectors is less than 0.5 percent, the owner or operator shall survey a random sample of 200 connectors once every 4 years.

(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 owner or operator 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 paragraphs (c)(1) through (c)(7) of this section. The program does not apply to inaccessible or unsafe-to-monitor connectors.

(1) Within 12 months after the phase III compliance date specified in §63.640(h), all connectors in gas/vapor service shall be monitored using Method 21 of 40 CFR part 60 appendix A. The instrument reading that defines a leak is 1,000 parts per million.

(2) All connectors in light liquid service shall be inspected for leaks. A leak is detected if liquids are observed to be dripping at a rate greater than three drops per minute.

(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 paragraph (e) of this section. 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, connectors in gas/vapor service shall be monitored for leaks within the first 3 months after repair. Connectors in light liquid service shall be inspected for indications of leaks within the first 3 months after repair. A leak is detected if liquids are observed to be dripping at a rate greater than three drops per minute.

(5) After conducting the initial survey required in paragraphs (c)(1) and (c)(2) of this section, the owner or operator shall conduct subsequent monitoring at the frequencies specified in paragraphs (c)(5)(i) through (c)(5)(iii) of this section.

(i) If the percentage leaking connectors is 2.0 percent or greater, the owner or operator shall monitor or inspect, as applicable, the connectors once per year.

(ii) If the percentage leaking connectors is 1.0 percent or greater but less than 2.0 percent, the owner or operator shall monitor or inspect, as applicable, the connectors once every 2 years.

(iii) If the percentage leaking connectors is less than 1.0 percent, the owner or operator shall monitor or inspect, as applicable, the connectors once every 4 years.

(6) The percentage leaking connectors shall be calculated for connectors in gas/vapor service and for connectors in light liquid service. The data for the two groups of connectors shall not be pooled for the purpose of determining the percentage leaking connectors.

(i) The percentage leaking connectors shall be calculated as follows:

$$\% C_L = [(C_L - C_{AN})/C_t + C_c)] \times 100$$

where:

$\% C_L$ = Percentage leaking connectors.

C_L = Number of connectors including nonrepairables, measured at 1,000 parts per million or greater, by Method 21 of 40 CFR part 60, appendix A.

C_{AN} = Number of allowable nonrepairable connectors, as determined by monitoring, not to exceed 3 percent of the total connector population, C_t.

C_t = Total number of monitored connectors, including nonrepairables, in the process unit.

C_c = Optional credit for removed connectors = 0.67 × net number (*i.e.,* the total number of connectors removed minus the total added) of connectors in organic HAP service removed from the process unit after the applicability date set forth in §63.640(h)(3)(iii) for existing process units, and after the date of start-up for new process units. If credits are not taken, then $C_c = 0$.

(ii) Nonrepairable connectors shall be included in the calculation of percentage leaking connectors the first time the connector is identified as leaking and nonrepairable. Otherwise, a number of nonrepairable connectors up to a maximum of 1 percent per year of the total number of connectors in organic HAP service up to a maximum of 3 percent may be excluded from calculation of percentage leaking connectors for subsequent monitoring periods.

(iii) If the number of nonrepairable connectors exceeds 3 percent of the total number of connectors in organic HAP service, the number of nonrepairable connectors exceeding 3 percent of the total number shall be included in the calculation of the percentage leaking connectors.

(7) 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.

(d) *Subpart H program.* The owner or operator shall implement a program to comply with the provisions in §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 owner or operator 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 paragraphs (b)(3) and (b)(4), (c)(3) and (c)(4), or (d) of this section if:

(1) The owner or operator determines that repair personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (b)(3) and (b)(4), (c)(3) and (c)(4), of this section; or

(2) The connector will be repaired before the end of the next scheduled process unit shutdown.

(g) The owner or operator 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.

[60 FR 43260, Aug. 18, 1995, as amended at 80 FR 75245, Dec. 1, 2015]

§63.650 Gasoline loading rack provisions.

(a) Except as provided in paragraphs (b) through (d) of this section, each owner or operator of a Group 1 gasoline loading rack classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a petroleum refinery shall comply with subpart R of this part, §§63.421, 63.422(a) through (c) and (e), 63.425(a) through (c) and (e) through (i), 63.427(a) and (b), and 63.428(b), (c), (g)(1), (h)(1) through (3), and (k).

(b) As used in this section, all terms not defined in §63.641 shall have the meaning given them in subpart A or in 40 CFR part 63, subpart R. The §63.641 definition of “affected source” applies under this section.

(c) Gasoline loading racks regulated under this subpart are subject to the compliance dates specified in §63.640(h).

(d) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of subpart R of this part, or the requirements of §63.670.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 74 FR 55685, Oct. 28, 2009; 80 FR 75245, Dec. 1, 2015]

§63.651 Marine tank vessel loading operation provisions.

(a) Except as provided in paragraphs (b) through (e) of this section, each owner or operator of a marine tank vessel loading operation located at a petroleum refinery shall comply with the requirements of §§63.560 through 63.568.

(b) As used in this section, all terms not defined in §63.641 shall have the meaning given them in subpart A or in 40 CFR part 63, subpart Y. The §63.641 definition of “affected source” applies under this section.

(c) The notification reports under §63.567(b) are not required.

(d) The compliance time of 4 years after promulgation of 40 CFR part 63, subpart Y, does not apply. The compliance time is specified in §63.640(h)(1).

(e) If a flare is used as a control device, on and after January 30, 2019, the flare shall meet the requirements of §63.670. Prior to January 30, 2019, the flare shall meet the applicable requirements of subpart Y of this part, or the requirements of §63.670.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 74 FR 55685, Oct. 28, 2009; 80 FR 75246, Dec. 1, 2015]

§63.652 Emissions averaging provisions.

(a) This section applies to owners or operators of existing sources who seek 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 §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651. Existing marine tank vessel loading operations located at the Valdez Marine Terminal source may not comply with the standard by using emissions averaging.

(b) The owner or operator shall develop and submit for approval an Implementation Plan containing all of the information required in §63.653(d) for all points to be included in an emissions average. The Implementation Plan shall identify all emission points to be included in the emissions average. This must include any Group 1 emission points to which the reference control technology (defined in §63.641) is not applied and all other emission points being controlled as part of the average.

(c) The following emission points can be used to generate emissions averaging credits if control was applied after November 15, 1990 and if sufficient information is available to determine the appropriate value of credits for the emission point:

(1) Group 2 emission points;

(2) Group 1 storage vessels, Group 1 wastewater streams, Group 1 gasoline loading racks, Group 1 marine tank vessels, and Group 1 miscellaneous process vents that are controlled by a technology that the Administrator or permitting authority agrees has a higher nominal efficiency than the reference control technology. Information on the nominal efficiencies for such technologies must be submitted and approved as provided in paragraph (i) of this section; and

(3) Emission points from which emissions are reduced by pollution prevention measures. Percentages of reduction for pollution prevention measures shall be determined as specified in paragraph (j) of this section.

(i) For a Group 1 emission point, the pollution prevention measure must reduce emissions more than the reference control technology would have had the reference control technology been applied to the emission point instead of the pollution prevention measure except as provided in paragraph (c)(3)(ii) of this section.

(ii) If a pollution prevention measure is used in conjunction with other controls for a Group 1 emission point, the pollution prevention measure alone does not have to reduce emissions more than the reference control technology, but the combination of the pollution prevention measure and other controls must reduce emissions more than the reference control technology would have had it been applied instead.

(d) The following emission points cannot be used to generate emissions averaging credits:

(1) Emission points already controlled on or before November 15, 1990 unless the level of control is increased after November 15, 1990, in which case credit will be allowed only for the increase in control after November 15, 1990;

(2) Group 1 emission points that are controlled by a reference control technology unless the reference control technology has been approved for use in a different manner and a higher nominal efficiency has been assigned according to the procedures in paragraph (i) of this section. For example, it is not allowable to claim that an internal floating roof meeting only the specifications stated in the reference control technology definition in §63.641 (i.e., that meets the specifications of §63.119(b) of subpart G but does not have controlled fittings per §63.119 (b)(5) and (b)(6) of subpart G) applied to a storage vessel is achieving greater than 95 percent control;

(3) Emission points on shutdown process units. Process units that are shut down cannot be used to generate credits or debits;

(4) Wastewater that is not process wastewater or wastewater streams treated in biological treatment units. These two types of wastewater cannot be used to generate credits or debits. Group 1 wastewater streams cannot be left undercontrolled or uncontrolled to generate debits. For the purposes of this section, the terms “wastewater” and “wastewater stream” are used to mean process wastewater; and

(5) Emission points controlled to comply with a State or Federal rule other than this subpart, unless the level of control has been increased after November 15, 1990 above what is required by the other State or Federal rule. Only the control above what is required by the other State or Federal rule will be credited. However, if an emission point has been used to generate emissions averaging credit in an approved emissions average, and the point is subsequently made subject to a State or Federal rule other than this subpart, the point can continue to generate emissions averaging credit for the purpose of complying with the previously approved average.

(e) For all points included in an emissions average, the owner or operator shall:

(1) Calculate and record monthly debits for all Group 1 emission points that are controlled to a level less stringent than the reference control technology for those emission points. Equations in paragraph (g) of this section shall be used to calculate debits.

(2) Calculate and record monthly credits for all Group 1 or Group 2 emission points that are overcontrolled to compensate for the debits. Equations in paragraph (h) of this section shall be used to calculate credits. Emission points and controls that meet the criteria of paragraph (c) of this section may be included in the credit calculation, whereas those described in paragraph (d) of this section shall not be included.

(3) Demonstrate that annual credits calculated according to paragraph (h) of this section are greater than or equal to debits calculated for the same annual compliance period according to paragraph (g) of this section.

(i) The initial demonstration in the Implementation Plan that credit-generating emission points will be capable of generating sufficient credits to offset the debits from the debit-generating emission points must be made under representative operating conditions.

(ii) After the compliance date, actual operating data will be used for all debit and credit calculations.

(4) Demonstrate that debits calculated for a quarterly (3-month) period according to paragraph (g) of this section are not more than 1.30 times the credits for the same period calculated according to paragraph (h) of this section. Compliance for the quarter shall be determined based on the ratio of credits and debits from that quarter, with 30 percent more debits than credits allowed on a quarterly basis.

(5) Record and report quarterly and annual credits and debits in the Periodic Reports as specified in §63.655(g)(8). Every fourth Periodic Report shall include a certification of compliance with the emissions averaging provisions as required by §63.655(g)(8)(iii).

(f) Debits and credits shall be calculated in accordance with the methods and procedures specified in paragraphs (g) and (h) of this section, respectively, and shall not include emissions from the following:

(1) More than 20 individual emission points. Where pollution prevention measures (as specified in paragraph (j)(1) of this section) are used to control emission points to be included in an emissions average, no more than 25 emission points may be included in the average. For example, if two emission points to be included in an emissions average are controlled by pollution prevention measures, the average may include up to 22 emission points.

(2) Periods of startup, shutdown, and malfunction as described in the source's startup, shutdown, and malfunction plan required by §63.6(e)(3) of subpart A of this part.

(3) For emission points for which continuous monitors are used, periods of excess emissions as defined in §63.655(g)(6)(i). For these periods, the calculation of monthly credits and debits shall be adjusted as specified in paragraphs (f)(3)(i) through (f)(3)(iii) of this section.

(i) No credits would be assigned to the credit-generating emission point.

(ii) Maximum debits would be assigned to the debit-generating emission point.

(iii) The owner or operator may use the procedures in paragraph (l) of this section to demonstrate to the Administrator that full or partial credits or debits should be assigned.

(g) Debits are generated by the difference between the actual emissions from a Group 1 emission point that is uncontrolled or is controlled to a level less stringent than the reference control technology, and the emissions allowed for Group 1 emission point. Debits shall be calculated as follows:

(1) The overall equation for calculating sourcewide debits is:

$$Debits = \sum_{i=1}^{n}\left(EPV_{iACTUAL} - (0.02)\,EPV_{iu}\right) + \sum_{i=1}^{n}\left(ES_{iACTUAL} - (0.05)\,ES_{iu}\right) + \sum_{i=1}^{n}\left(EGLR_{iACTUAL} - EGLR_{iC}\right) + \sum_{i=1}^{n}\left(EMV_{iACTUAL} - (0.03)\,EMViu\right)$$

where:

Debits and all terms of the equation are in units of megagrams per month, and

$EPV_{iACTUAL}$ = Emissions from each Group 1 miscellaneous process vent i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(2) of this section.

(0.02) EPV_{iu} = Emissions from each Group 1 miscellaneous process vent i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (g)(2) of this section.

$ES_{iACTUAL}$ = Emissions from each Group 1 storage vessel i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(3) of this section.

(0.05) ES_{iu} = Emissions from each Group 1 storage vessel i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (g)(3) of this section.

$EGLR_{iACTUAL}$ = Emissions from each Group 1 gasoline loading rack i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(4) of this section.

$EGLR_{ic}$ = Emissions from each Group 1 gasoline loading rack i if the reference control technology had been applied to the uncontrolled emissions. This is calculated according to paragraph (g)(4) of this section.

EMV_{ACTUAL} = Emissions from each Group 1 marine tank vessel i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(5) of this section.

(0.03) EMV_{iu} = Emissions from each Group 1 marine tank vessel i if the reference control technology had been applied to the uncontrolled emissions calculated according to paragraph (g)(5) of this section.

n = The number of Group 1 emission points being included in the emissions average. The value of n is not necessarily the same for each kind of emission point.

(2) Emissions from miscellaneous process vents shall be calculated as follows:

(i) For purposes of determining miscellaneous process vent stream flow rate, organic HAP concentrations, and temperature, the sampling site shall be after the final product recovery device, if any recovery devices are present; before any control device (for miscellaneous process vents, recovery devices shall not be considered control devices); and before discharge to the atmosphere. Method 1 or 1A of part 60, appendix A shall be used for selection of the sampling site.

(ii) The following equation shall be used for each miscellaneous process vent i to calculate EPV_{iu}:

$$EPV_{iu} = \left(2.494 \times 10^{-9}\right) Qh \left(\sum_{j=1}^{n} C_j M_j\right)$$

where:

EPV_{iu} = Uncontrolled process vent emission rate from miscellaneous process vent i, megagrams per month.

Q = Vent stream flow rate, dry standard cubic meters per minute, measured using Methods 2, 2A, 2C, or 2D of part 60 appendix A, as appropriate.

h = Monthly hours of operation during which positive flow is present in the vent, hours per month.

C_j = Concentration, parts per million by volume, dry basis, of organic HAP j as measured by Method 18 of part 60 appendix A.

M_j = Molecular weight of organic HAP j, gram per gram-mole.

n = Number of organic HAP's in the miscellaneous process vent stream.

(A) The values of Q, C_j, and M_j shall be determined during a performance test conducted under representative operating conditions. The values of Q, C_j, and M_j shall be established in the Notification of Compliance Status report and must be updated as provided in paragraph (g)(2)(ii)(B) of this section.

(B) If there is a change in capacity utilization other than a change in monthly operating hours, or if any other change is made to the process or product recovery equipment or operation such that the previously measured values of Q, C_j, and M_j are no longer representative, a new performance test shall be conducted to determine new representative values of Q, C_j, and M_j. These new values shall be used to calculate debits and credits from the time of the change forward, and the new values shall be reported in the next Periodic Report.

(iii) The following procedures and equations shall be used to calculate $EPV_{iACTUAL}$:

(A) If the vent is not controlled by a control device or pollution prevention measure, $EPV_{iACTUAL} = EPV_{iu}$, where EPV_{iu} is calculated according to the procedures in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(B) If the vent is controlled using a control device or a pollution prevention measure achieving less than 98-percent reduction,

$$EPV_{iACTUAL} = EPV_{iu} \times \left(1 - \frac{Percent\ reduction}{100\%}\right)$$

(*1*) The percent reduction shall be measured according to the procedures in §63.116 of subpart G if a combustion control device is used. For a flare meeting the criteria in §63.116(a) of subpart G or §63.670, as applicable, or a boiler or process heater meeting the criteria in §63.645(d) or §63.116(b) of subpart G, the percentage of reduction shall be 98 percent. If a noncombustion control device is used, percentage of reduction shall be demonstrated by a performance test at the inlet and outlet of the device, or, if testing is not feasible, by a control design evaluation and documented engineering calculations.

(*2*) For determining debits from miscellaneous process vents, product recovery devices shall not be considered control devices and cannot be assigned a percentage of reduction in calculating $EPV_{iACTUAL}$. The sampling site for measurement of uncontrolled emissions is after the final product recovery device.

(*3*) Procedures for calculating the percentage of reduction of pollution prevention measures are specified in paragraph (j) of this section.

(3) Emissions from storage vessels shall be calculated as specified in §63.150(g)(3) of subpart G.

(4) Emissions from gasoline loading racks shall be calculated as follows:

(i) The following equation shall be used for each gasoline loading rack i to calculate $EGLR_{iu}$:

$$EGLR_{iu} = \left(1.20 \times 10^{-7}\right) \frac{SPMG}{T}$$

where:

$EGLR_{iu}$ = Uncontrolled transfer HAP emission rate from gasoline loading rack i, megagrams per month

S = Saturation factor, dimensionless (see table 33 of subpart G).

P = Weighted average rack partial pressure of organic HAP's transferred at the rack during the month, kilopascals.

M = Weighted average molecular weight of organic HAP's transferred at the gasoline loading rack during the month, gram per gram-mole.

G = Monthly volume of gasoline transferred from gasoline loading rack, liters per month.

T = Weighted rack bulk liquid loading temperature during the month, degrees kelvin (degrees Celsius °C + 273).

(ii) The following equation shall be used for each gasoline loading rack i to calculate the weighted average rack partial pressure:

$$P = \frac{\sum_{1}^{j=n} (P_j)(G_j)}{G}$$

where:

P_j = Maximum true vapor pressure of individual organic HAP transferred at the rack, kilopascals.

G = Monthly volume of organic HAP transferred, liters per month, and

$$G = \sum_{1}^{j=n} G_j$$

G_j = Monthly volume of individual organic HAP transferred at the gasoline loading rack, liters per month.

n = Number of organic HAP's transferred at the gasoline loading rack.

(iii) The following equation shall be used for each gasoline loading rack i to calculate the weighted average rack molecular weight:

$$M = \frac{\sum_{1}^{j=n} (M_j)(G_j)}{G}$$

where:

M_j = Molecular weight of individual organic HAP transferred at the rack, gram per gram-mole.

G, G_j, and n are as defined in paragraph (g)(4)(ii) of this section.

(iv) The following equation shall be used for each gasoline loading rack i to calculate the monthly weighted rack bulk liquid loading temperature:

$$T = \frac{\sum_{1}^{j=n} (T_j)(G_j)}{G}$$

T_j = Average annual bulk temperature of individual organic HAP loaded at the gasoline loading rack, kelvin (degrees Celsius °C + 273).

G, G_j, and n are as defined in paragraph (g)(4)(ii) of this section.

(v) The following equation shall be used to calculate $EGLR_{ic}$:

$$EGLR_{ic} = 1 \times 10^{-8} G$$

G is as defined in paragraph (g)(4)(ii) of this section.

(vi) The following procedures and equations shall be used to calculate $EGLR_{iACTUAL}$:

(A) If the gasoline loading rack is not controlled, $EGLR_{iACTUAL} = EGLR_{iu}$, where $EGLR_{iu}$ is calculated using the equations specified in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(B) If the gasoline loading rack is controlled using a control device or a pollution prevention measure not achieving the requirement of less than 10 milligrams of TOC per liter of gasoline loaded,

$$EGLR_{iACTUAL} = EGLR_{iu}\left(\frac{1 - Percent\ reduction}{100\%}\right)$$

(*1*) The percent reduction for a control device shall be measured according to the procedures and test methods specified in §63.128(a) of subpart G. If testing is not feasible, the percentage of reduction shall be determined through a design evaluation according to the procedures specified in §63.128(h) of subpart G.

(*2*) Procedures for calculating the percentage of reduction for pollution prevention measures are specified in paragraph (j) of this section.

(5) Emissions from marine tank vessel loading shall be calculated as follows:

(i) The following equation shall be used for each marine tank vessel i to calculate EMV_{iu}:

$$EMV_{iu} = \sum_{i=1}^{m}(Q_i)(F_i)(P_i)$$

where:

EMV_{iu} = Uncontrolled marine tank vessel HAP emission rate from marine tank vessel i, megagrams per month.

Q_i = Quantity of commodity loaded (per vessel type), liters.

F_i = Emission factor, megagrams per liter.

P_i = Percent HAP.

m = Number of combinations of commodities and vessel types loaded.

Emission factors shall be based on test data or emission estimation procedures specified in §63.565(l) of subpart Y.

(ii) The following procedures and equations shall be used to calculate $EMV_{iACTUAL}$:

(A) If the marine tank vessel is not controlled, $EMV_{iACTUAL} = EMV_{iu}$, where EMV_{iu} is calculated using the equations specified in paragraph (g)(5)(i) of this section.

(B) If the marine tank vessel is controlled using a control device or a pollution prevention measure achieving less than 97-percent reduction,

$$EMV_{iACTUAL} = EMV_{iu}\left(\frac{1 - Percent\ reduction}{100\%}\right)$$

(*1*) The percent reduction for a control device shall be measured according to the procedures and test methods specified in §63.565(d) of subpart Y. If testing is not feasible, the percentage of reduction shall be determined through a design evaluation according to the procedures specified in §63.128(h) of subpart G.

(*2*) Procedures for calculating the percentage of reduction for pollution prevention measures are specified in paragraph (j) of this section.

(h) Credits are generated by the difference between emissions that are allowed for each Group 1 and Group 2 emission point and the actual emissions from a Group 1 or Group 2 emission point that has been controlled after November 15, 1990 to a level more stringent than what is required by this subpart or any other State or Federal rule or statute. Credits shall be calculated as follows:

(1) The overall equation for calculating sourcewide credits is:

$$
\begin{aligned}
Credits = {} & D\sum_{i=1}^{n}\left((0.02)\ \mathrm{EPV1}_{iu} - EPV1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(EPV2_{iBASE} - EPV2_{iACTUAL}\right) + \\
& D\sum_{i=1}^{n}\left((0.05)\ \mathrm{ES1}_{iu} - ES1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(ES2_{iBASE} - ES2_{iACTUAL}\right) + \\
& D\sum_{i=1}^{n}\left(\ \mathrm{EGLR}_{ic} - EGLR1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(EGLR2_{iBASE} - EGLR2_{iACTUAL}\right) + \\
& D\sum_{i=1}^{n}\left((0.03)\ \mathrm{EMV1}_{iu} - EMV1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(EMV2_{iBASE} - EMV2_{iACTUAL}\right) + \\
& D\sum_{i=1}^{n}\left(\mathrm{EWW1}_{ic} - EWW1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(EWW2_{iBASE} - EWW2_{iACTUAL}\right)
\end{aligned}
$$

where:

Credits and all terms of the equation are in units of megagrams per month, the baseline date is November 15, 1990, and

D = Discount factor = 0.9 for all credit-generating emission points except those controlled by a pollution prevention measure, which will not be discounted.

$EPV1_{iACTUAL}$ = Emissions for each Group 1 miscellaneous process vent i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(2) of this section.

(0.02) $EPV1_{iu}$ = Emissions from each Group 1 miscellaneous process vent i if the reference control technology had been applied to the uncontrolled emissions. $EPV1_{iu}$ is calculated according to paragraph (h)(2) of this section.

$EPV2_{iBASE}$ = Emissions from each Group 2 miscellaneous process vent; at the baseline date, as calculated in paragraph (h)(2) of this section.

$EPV2_{iACTUAL}$ = Emissions from each Group 2 miscellaneous process vent that is controlled, calculated according to paragraph (h)(2) of this section.

$ES1_{iACTUAL}$ = Emissions from each Group 1 storage vessel i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(3) of this section.

(0.05) $ES1_{iu}$ = Emissions from each Group 1 storage vessel i if the reference control technology had been applied to the uncontrolled emissions. $ES1_{iu}$ is calculated according to paragraph (h)(3) of this section.

$ES2_{iACTUAL}$ = Emissions from each Group 2 storage vessel i that is controlled, calculated according to paragraph (h)(3) of this section.

$ES2_{iBASE}$ = Emissions from each Group 2 storage vessel i at the baseline date, as calculated in paragraph (h)(3) of this section.

$EGLR1_{iACTUAL}$ = Emissions from each Group 1 gasoline loading rack i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(4) of this section.

$EGLR_{ic}$ = Emissions from each Group 1 gasoline loading rack i if the reference control technology had been applied to the uncontrolled emissions. $EGLR_{iu}$ is calculated according to paragraph (h)(4) of this section.

$EGRL2_{iACTUAL}$ = Emissions from each Group 2 gasoline loading rack i that is controlled, calculated according to paragraph (h)(4) of this section.

$EGLR2_{iBASE}$ = Emissions from each Group 2 gasoline loading rack i at the baseline date, as calculated in paragraph (h)(4) of this section.

$EMV1_{iACTUAL}$ = Emissions from each Group 1 marine tank vessel i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(4) of this section.

(0.03)$EMV1_{iu}$ = Emissions from each Group 1 marine tank vessel i if the reference control technology had been applied to the uncontrolled emissions. $EMV1_{iu}$ is calculated according to paragraph (h)(5) of this section.

$EMV2_{iACTUAL}$ = Emissions from each Group 2 marine tank vessel i that is controlled, calculated according to paragraph (h)(5) of this section.

$EMV2_{iBASE}$ = Emissions from each Group 2 marine tank vessel i at the baseline date, as calculated in paragraph (h)(5) of this section.

$EWW1_{iACTUAL}$ = Emissions from each Group 1 wastewater stream i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(6) of this section.

$EWW1_{ic}$ = Emissions from each Group 1 wastewater stream i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (h)(6) of this section.

$EWW2_{iACTUAL}$ = Emissions from each Group 2 wastewater stream i that is controlled, calculated according to paragraph (h)(6) of this section.

$EWW2_{iBASE}$ = Emissions from each Group 2 wastewater stream i at the baseline date, calculated according to paragraph (h)(6) of this section.

n = Number of Group 1 emission points included in the emissions average. The value of n is not necessarily the same for each kind of emission point.

m = Number of Group 2 emission points included in the emissions average. The value of m is not necessarily the same for each kind of emission point.

(i) For an emission point controlled using a reference control technology, the percentage of reduction for calculating credits shall be no greater than the nominal efficiency associated with the reference control technology, unless a higher nominal efficiency is assigned as specified in paragraph (h)(1)(ii) of this section.

(ii) For an emission point controlled to a level more stringent than the reference control technology, the nominal efficiency for calculating credits shall be assigned as described in paragraph (i) of this section. A reference control technology may be approved for use in a different manner and assigned a higher nominal efficiency according to the procedures in paragraph (i) of this section.

(iii) For an emission point controlled using a pollution prevention measure, the nominal efficiency for calculating credits shall be determined as described in paragraph (j) of this section.

(2) Emissions from process vents shall be determined as follows:

(i) Uncontrolled emissions from miscellaneous process vents, $EPV1_{iu}$, shall be calculated according to the procedures and equation for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(ii) Actual emissions from miscellaneous process vents controlled using a technology with an approved nominal efficiency greater than 98 percent or a pollution prevention measure achieving greater than 98 percent emission reduction, $EPV1_{iACTUAL}$, shall be calculated according to the following equation:

$$EPV1_{iACTUAL} = EPV1_{iu}\left(1 - \frac{Nominal\ efficiency\ \%}{100\%}\right)$$

(iii) The following procedures shall be used to calculate actual emissions from Group 2 process vents, $EPV2_{iACTUAL}$:

(A) For a Group 2 process vent controlled by a control device, a recovery device applied as a pollution prevention project, or a pollution prevention measure, if the control achieves a percentage of reduction less than or equal to a 98 percent reduction,

$$EPV2_{iACTUAL} = EPV2_{iu} \times \left(1 - \frac{Percent\ reduction}{100\%}\right)$$

(*1*) $EPV2_{iu}$ shall be calculated according to the equations and procedures for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section except as provided in paragraph (h)(2)(iii)(A)(*3*) of this section.

(*2*) The percentage of reduction shall be calculated according to the procedures in paragraphs (g)(2)(iii)(B)(*1*) through (g)(2)(iii)(B)(*3*) of this section except as provided in paragraph (h)(2)(iii)(A)(*4*) of this section.

(*3*) If a recovery device was added as part of a pollution prevention project, $EPV2_{iu}$ shall be calculated prior to that recovery device. The equation for EPV_{iu} in paragraph (g)(2)(ii) of this section shall be used to calculate $EPV2_{iu}$; however, the sampling site for measurement of vent stream flow rate and organic HAP concentration shall be at the inlet of the recovery device.

(*4*) If a recovery device was added as part of a pollution prevention project, the percentage of reduction shall be demonstrated by conducting a performance test at the inlet and outlet of that recovery device.

(B) For a Group 2 process vent controlled using a technology with an approved nominal efficiency greater than a 98 percent or a pollution prevention measure achieving greater than 98 percent reduction,

$$EPV2_{iACTUAL} = EPV2_{iu}\left(1 - \frac{Nominal\ efficiency\ \%}{100\%}\right)$$

(iv) Emissions from Group 2 process vents at baseline, $EPV2_{iBASE}$, shall be calculated as follows:

(A) If the process vent was uncontrolled on November 15, 1990, $EPV2_{iBASE}$ = $EPV2_{iu}$, and shall be calculated according to the procedures and equation for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(B) If the process vent was controlled on November 15, 1990,

$$EPV2_{BASE} = EPV2_{iu}\left(1 - \frac{Percent\ reduction\,\%}{100\%}\right)$$

where $EPV2_{iu}$ is calculated according to the procedures and equation for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section. The percentage of reduction shall be calculated according to the procedures specified in paragraphs (g)(2)(iii)(B)(*1*) through (g)(2)(iii)(B)(*3*) of this section.

(C) If a recovery device was added to a process vent as part of a pollution prevention project initiated after November 15, 1990, $EPV2_{iBASE}$ = $EPV2_{iu}$, where $EPV2_{iu}$ is calculated according to paragraph (h)(2)(iii)(A)(*3*) of this section.

(3) Emissions from storage vessels shall be determined as specified in §63.150(h)(3) of subpart G, except as follows:

(i) All references to §63.119(b) in §63.150(h)(3) of subpart G shall be replaced with: §63.119 (b) or §63.119(b) except for §63.119(b)(5) and (b)(6).

(ii) All references to §63.119(c) in §63.150(h)(3) of subpart G shall be replaced with: §63.119(c) or §63.119(c) except for §63.119(c)(2).

(iii) All references to §63.119(d) in §63.150(h)(3) of subpart G shall be replaced with: §63.119(d) or §63.119(d) except for §63.119(d)(2).

(4) Emissions from gasoline loading racks shall be determined as follows:

(i) Uncontrolled emissions from Group 1 gasoline loading racks, $EGLR1_{iu}$, shall be calculated according to the procedures and equations for $EGLR_{iu}$ as described in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(ii) Emissions from Group 1 gasoline loading racks if the reference control technology had been applied, $EGLR_{ic}$, shall be calculated according to the procedures and equations in paragraph (g)(4)(v) of this section.

(iii) Actual emissions from Group 1 gasoline loading racks controlled to less than 10 milligrams of TOC per liter of gasoline loaded; $EGLR_{iACTUAL}$, shall be calculated according to the following equation:

$$EGLR1_{iACTUAL} = EGLR1_{iu}\left(1 - \frac{Nominal\ efficiency}{100\%}\right)$$

(iv) The following procedures shall be used to calculate actual emissions from Group 2 gasoline loading racks, $EGLR2_{iACTUAL}$:

(A) For a Group 2 gasoline loading rack controlled by a control device or a pollution prevention measure achieving emissions reduction but where emissions are greater than the 10 milligrams of TOC per liter of gasoline loaded requirement,

$$EGLR2_{iACTUAL} = EGLR2_{iu}\left(1 - \frac{Percent\ \mathrm{reduction}}{100\%}\right)$$

(*1*) $EGLR2_{iu}$ shall be calculated according to the equations and procedures for $EGLR_{iu}$ in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(*2*) The percentage of reduction shall be calculated according to the procedures in paragraphs (g)(4)(vi)(B)(*1*) and (g)(4)(vi)(B)(*2*) of this section.

(B) For a Group 2 gasoline loading rack controlled by using a technology with an approved nominal efficiency greater than 98 percent or a pollution prevention measure achieving greater than a 98-percent reduction,

$$EGLR2_{iACTUAL} = EGLR2_{iu}\left(1-\frac{\text{Nominal efficiency}}{100\%}\right)$$

(v) Emissions from Group 2 gasoline loading racks at baseline, $EGLR2_{iBASE}$, shall be calculated as follows:

(A) If the gasoline loading rack was uncontrolled on November 15, 1990, $EGLR2_{iBASE} = EGLR2_{iu}$, and shall be calculated according to the procedures and equations for $EGLR_{iu}$ in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(B) If the gasoline loading rack was controlled on November 15, 1990,

$$EGLR2_{iBASE} = EGLR2_{iu}\left(1-\frac{\textit{Percent}\text{ reduction}}{100\%}\right)$$

where $EGLR2_{iu}$ is calculated according to the procedures and equations for $EGLR_{iu}$ in paragraphs (g)(4)(i) through (g)(4)(iv) of this section. Percentage of reduction shall be calculated according to the procedures in paragraphs (g)(4)(vi)(B)(*1*) and (g)(4)(vi)(B)(*2*) of this section.

(5) Emissions from marine tank vessels shall be determined as follows:

(i) Uncontrolled emissions from Group 1 marine tank vessels, $EMV1_{iu}$, shall be calculated according to the procedures and equations for EMV_{iu} as described in paragraph (g)(5)(i) of this section.

(ii) Actual emissions from Group 1 marine tank vessels controlled using a technology or pollution prevention measure with an approved nominal efficiency greater than 97 percent, $EMV_{iACTUAL}$, shall be calculated according to the following equation:

$$EMV1_{iACTUAL} = EMV1_{iu}\left(1-\frac{\text{Nominal efficiency}}{100\%}\right)$$

(iii) The following procedures shall be used to calculate actual emissions from Group 2 marine tank vessels, $EMV2_{iACTUAL}$:

(A) For a Group 2 marine tank vessel controlled by a control device or a pollution prevention measure achieving a percentage of reduction less than or equal to 97 percent reduction,

$$EMV2_{iACTUAL} = EMV2_{iu}\left(1-\frac{\textit{Percent}\text{ reduction}}{100\%}\right)$$

(*1*) $EMV2_{iu}$ shall be calculated according to the equations and procedures for EMV_{iu} in paragraph (g)(5)(i) of this section.

(*2*) The percentage of reduction shall be calculated according to the procedures in paragraphs (g)(5)(ii)(B)(*1*) and (g)(5)(ii)(B)(*2*) of this section.

(B) For a Group 2 marine tank vessel controlled using a technology or a pollution prevention measure with an approved nominal efficiency greater than 97 percent,

$$EMV2_{iACTUAL} = EMV2_{iu}\left(1 - \frac{\text{Nominal efficiency}}{100\%}\right)$$

(iv) Emissions from Group 2 marine tank vessels at baseline, $EMV2_{iBASE}$, shall be calculated as follows:

(A) If the marine terminal was uncontrolled on November 15, 1990, $EMV2_{iBASE}$ equals $EMV2_{iu}$, and shall be calculated according to the procedures and equations for EMV_{iu} in paragraph (g)(5)(i) of this section.

(B) If the marine tank vessel was controlled on November 15, 1990,

$$EMV2_{iBASE} = EMV2_{iu}\left(1 - \frac{\mathit{Percent}\ \text{reduction}}{100\%}\right)$$

where $EMV2_{iu}$ is calculated according to the procedures and equations for EMV_{iu} in paragraph (g)(5)(i) of this section. Percentage of reduction shall be calculated according to the procedures in paragraphs (g)(5)(ii)(B)(*1*) and (g)(5)(ii)(B)(*2*) of this section.

(6) Emissions from wastewater shall be determined as follows:

(i) For purposes of paragraphs (h)(4)(ii) through (h)(4)(vi) of this section, the following terms will have the meaning given them in paragraphs (h)(6)(i)(A) through (h)(6)(i)(C) of this section.

(A) *Correctly suppressed* means that a wastewater stream is being managed according to the requirements of §§61.343 through 61.347 or §61.342(c)(l)(iii) of 40 CFR part 61, subpart FF, as applicable, and the emissions from the waste management units subject to those requirements are routed to a control device that reduces HAP emissions by 95 percent or greater.

(B) *Treatment process* has the meaning given in §61.341 of 40 CFR part 61, subpart FF except that it does not include biological treatment units.

(C) *Vapor control device* means the control device that receives emissions vented from a treatment process or treatment processes.

(ii) The following equation shall be used for each wastewater stream i to calculate EWW_{ic}:

$$EWW_{ic} = \left(6.0*10^{-8}\right)Q_i\,H_i\sum_{m=1}^{5}\left(1 - Fr_m\right)Fe_m HAP_{im} + \left(0.05\right)\left(6.0*10^{-8}\right)Q_i\,H_i\sum_{m=1}^{5}\left(Fr_m HAP_{im}\right)$$

where:

EWW_{ic} = Monthly wastewater stream emission rate if wastewater stream i were controlled by the reference control technology, megagrams per month.

Q_i = Average flow rate for wastewater stream i, liters per minute.

H_i = Number of hours during the month that wastewater stream i was generated, hours per month.

Fr_m = Fraction removed of organic HAP m in wastewater, from table 7 of this subpart, dimensionless.

Fe_m = Fraction emitted of organic HAP m in wastewater from table 7 of this subpart, dimensionless.

s = Total number of organic HAP's in wastewater stream i.

HAP_{im} = Average concentration of organic HAP m in wastewater stream i, parts per million by weight.

(A) HAP_{im} shall be determined for the point of generation or at a location downstream of the point of generation. Wastewater samples shall be collected using the sampling procedures specified in Method 25D of 40 CFR part 60, appendix A. Where feasible, samples shall be taken from an enclosed pipe prior to the wastewater being exposed to the atmosphere. When sampling from an enclosed pipe is not feasible, a minimum of three representative samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of organic HAP's prior to sampling. The samples collected may be analyzed by either of the following procedures:

(*1*) A test method or results from a test method that measures organic HAP concentrations in the wastewater, and that has been validated pursuant to section 5.1 or 5.3 of Method 301 of appendix A of this part may be used; or

(*2*) Method 305 of appendix A of this part may be used to determine C_{im}, the average volatile organic HAP concentration of organic HAP m in wastewater stream i, and then HAP_{im} may be calculated using the following equation: $HAP_{im} = C_{im}/Fm_m$, where Fm_m for organic HAP m is obtained from table 7 of this subpart.

(B) Values for Q_i, HAP_{im}, and C_{im} shall be determined during a performance test conducted under representative conditions. The average value obtained from three test runs shall be used. The values of Q_i, HAP_{im}, and C_{im} shall be established in the Notification of Compliance Status report and must be updated as provided in paragraph (h)(6)(i)(C) of this section.

(C) If there is a change to the process or operation such that the previously measured values of Q_i, HAP_{im}, and C_{im} are no longer representative, a new performance test shall be conducted to determine new representative values of Q_i, HAP_{im}, and C_{im}. These new values shall be used to calculate debits and credits from the time of the change forward, and the new values shall be reported in the next Periodic Report.

(iii) The following equations shall be used to calculate $EWW1_{iACTUAL}$ for each Group 1 wastewater stream i that is correctly suppressed and is treated to a level more stringent than the reference control technology.

(A) If the Group 1 wastewater stream i is controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated HAP that is greater than that specified in table 7 of this subpart, and the vapor control device achieves a percentage of reduction equal to 95 percent, the following equation shall be used:

$$EWW1_{iACTUAL} = \left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{s} \left[Fe_m HAP_{im}\left(1-PR_{im}\right)\right] + 0.05\left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{s} \left[HAP_{im} PR_{im}\right]$$

Where:

$EWW_{iACTUAL}$ = Monthly wastewater stream emission rate if wastewater stream i is treated to a level more stringent than the reference control technology, megagrams per month.

PR_{im} = The efficiency of the treatment process, or series of treatment processes, that treat wastewater stream i in reducing the emission potential of organic HAP m in wastewater, dimensionless, as calculated by:

$$PR_{im} = \frac{HAP_{im\text{-}in} - HAP_{im\text{-}out}}{HAP_{im\text{-}in}}$$

Where:

$HAP_{im\text{-}in}$ = Average concentration of organic HAP m, parts per million by weight, as defined and determined according to paragraph (h)(6)(ii)(A) of this section, in the wastewater entering the first treatment process in the series.

$HAP_{im\text{-}out}$ = Average concentration of organic HAP m, parts per million by weight, as defined and determined according to paragraph (h)(6)(ii)(A) of this section, in the wastewater exiting the last treatment process in the series.

All other terms are as defined and determined in paragraph (h)(6)(ii) of this section.

(B) If the Group 1 wastewater stream i is not controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated HAP that is greater than that specified in table 7 of this subpart, but the vapor control device has an approved nominal efficiency greater than 95 percent, the following equation shall be used:

$$EWW1_{iACTUAL} = \left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{s} \left[Fe_m HAP_{im}\left(1-A_m\right)\right] + \left(1-\frac{\text{Nominal efficiency \%}}{100}\right)\left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{s} \lbrack HA$$

Where:

Nominal efficiency = Approved reduction efficiency of the vapor control device, dimensionless, as determined according to the procedures in §63.652(i).

A_m = The efficiency of the treatment process, or series of treatment processes, that treat wastewater stream i in reducing the emission potential of organic HAP m in wastewater, dimensionless.

All other terms are as defined and determined in paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(*1*) If a steam stripper meeting the specifications in the definition of reference control technology for wastewater is used, A_m shall be equal to the value of Fr_m given in table 7 of this subpart.

(*2*) If an alternative control device is used, the percentage of reduction must be determined using the equation and methods specified in paragraph (h)(6)(iii)(A) of this section for determining PR_{im}. If the value of PR_{im} is greater than or equal to the value of Fr_m given in table 7 of this subpart, then A_m equals Fr_m unless a higher nominal efficiency has been approved. If a higher nominal efficiency has been approved for the treatment process, the owner or operator shall determine $EWW1_{iACTUAL}$ according to paragraph (h)(6)(iii)(B) of this section rather than paragraph (h)(6)(iii)(A) of this section. If PR_{im} is less than the value of FR_m given in table 7 of this subpart, emissions averaging shall not be used for this emission point.

(C) If the Group 1 wastewater stream i is controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated hazardous air pollutant that is greater than that specified in table 7 of this subpart, and the vapor control device has an approved nominal efficiency greater than 95 percent, the following equation shall be used:

$$EWW1_{iACTUAL} = \left(6.0*10^{-8}\right) Q_i H_i \sum_{m=1}^{s} \left[Fe_m HAP_{im}\left(1-PR_{im}\right)\right] + \left(1-\frac{\text{Nominal efficiency \%}}{100}\right)\left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{s} \lbrack HA$$

where all terms are as defined and determined in paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(iv) The following equation shall be used to calculate $EWW2_{iBASE}$ for each Group 2 wastewater stream i that on November 15, 1990 was not correctly suppressed or was correctly suppressed but not treated:

$$EWW2_{iBASE} = \left(6.0\times10^{-8}\right) Q_i\, H_i \sum_{m=1}^{s} Fe_m HAP_{im}$$

Where:

$EWW2_{iBASE}$ = Monthly wastewater stream emission rate if wastewater stream i is not correctly suppressed, megagrams per month.

Q_i, H_i, s, Fe_m, and HAP_{im} are as defined and determined according to paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(v) The following equation shall be used to calculate $EWW2_{iBASE}$ for each Group 2 wastewater stream i on November 15, 1990 was correctly suppressed. $EWW2_{iBASE}$ shall be calculated as if the control methods being used on November 15, 1990 are in place and any control methods applied after November 15, 1990 are ignored. However, values for the parameters in the equation shall be representative of present production levels and stream properties.

$$EWW2_{iBASE} = \left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{s} \left[Fe_m HAP_{im}\left(1 - PR_{im}\right)\right] + \left(1 - \frac{R_i}{100\%}\right)\left(6.0*10^{-8}\right) Q_i\, H_i \sum_{m=1}^{s} \left[HAP_{im} PR_{im}\right]$$

where R_i is calculated according to paragraph (h)(6)(vii) of this section and all other terms are as defined and determined according to paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(vi) For Group 2 wastewater streams that are correctly suppressed, $EWW2_{iACTUAL}$ shall be calculated according to the equation for $EWW2_{iBASE}$ in paragraph (h)(6)(v) of this section. $EWW2_{iACTUAL}$ shall be calculated with all control methods in place accounted for.

(vii) The reduction efficiency, R_i, of the vapor control device shall be demonstrated according to the following procedures:

(A) Sampling sites shall be selected using Method 1 or 1A of 40 CFR part 60, appendix A, as appropriate.

(B) The mass flow rate of organic compounds entering and exiting the control device shall be determined as follows:

(*1*) The time period for the test shall not be less than 3 hours during which at least three runs are conducted.

(*2*) A run shall consist of a 1-hour period during the test. For each run:

(*i*) The volume exhausted shall be determined using Methods 2, 2A, 2C, or 2D of 40 CFR part 60 appendix A, as appropriate;

(*ii*) The organic concentration in the vent stream entering and exiting the control device shall be determined using Method 18 of 40 CFR part 60, appendix A. Alternatively, any other test method validated according to the procedures in Method 301 of appendix A of this part may be used.

(*3*) The mass flow rate of organic compounds entering and exiting the control device during each run shall be calculated as follows:

$$E_a = \frac{0.0416}{10^6 \times m}\left[\sum_{p=1}^{m} V_{ap}\left(\sum_{p=1}^{n} C_{aip} MW_i\right)\right]$$

$$E_b = \frac{0.0416}{10^6 \times m}\left[\sum_{p=1}^{m} V_{bp}\left(\sum_{p=1}^{n} C_{bip} MW_i\right)\right]$$

Where:

E_a = Mass flow rate of organic compounds exiting the control device, kilograms per hour.

E_b = Mass flow rate of organic compounds entering the control device, kilograms per hour.

V_{ap} = Average volumetric flow rate of vent stream exiting the control device during run p at standards conditions, cubic meters per hour.

V_{bp} = Average volumetric flow rate of vent stream entering the control device during run p at standards conditions, cubic meters per hour.

p = Run.

m = Number of runs.

C_{aip} = Concentration of organic compound i measured in the vent stream exiting the control device during run p as determined by Method 18 of 40 CFR part 60 appendix A, parts per million by volume on a dry basis.

C_{bip} = Concentration of organic compound i measured in the vent stream entering the control device during run p as determined by Method 18 of 40 CFR part 60, appendix A, parts per million by volume on a dry basis.

MW_i = Molecular weight of organic compound i in the vent stream, kilograms per kilogram-mole.

n = Number of organic compounds in the vent stream.

0.0416 = Conversion factor for molar volume, kilograms-mole per cubic meter at 293 kelvin and 760 millimeters mercury absolute.

(C) The organic reduction efficiency for the control device shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b} \times 100$$

Where:

R = Total organic reduction efficiency for the control device, percentage.

E_b = Mass flow rate of organic compounds entering the control device, kilograms per hour.

E_a = Mass flow rate of organic compounds exiting the control device, kilograms per hour.

(i) The following procedures shall be followed to establish nominal efficiencies. The procedures in paragraphs (i)(1) through (i)(6) of this section shall be followed for control technologies that are different in use or design from the reference control technologies and achieve greater percentages of reduction than the percentages of efficiency assigned to the reference control technologies in §63.641.

(1) In those cases where the owner or operator is seeking permission to take credit for use of a control technology that is different in use or design from the reference control technology, and the different control technology will be used in more than three applications at a single plant site, the owner or operator shall submit the information specified in paragraphs (i)(1)(i) through (i)(1)(iv) of this section to the Administrator in writing:

(i) Emission stream characteristics of each emission point to which the control technology is or will be applied including the kind of emission point, flow, organic HAP concentration, and all other stream characteristics necessary to design the control technology or determine its performance;

(ii) Description of the control technology including design specifications;

(iii) Documentation demonstrating to the Administrator's satisfaction the control efficiency of the control technology. This may include performance test data collected using an appropriate EPA method or any other method validated according to Method 301 of appendix A of this part. If it is infeasible to obtain test data, documentation may include a design evaluation and calculations. The engineering basis of the calculation procedures and all inputs and assumptions made in the calculations shall be documented; and

(iv) A description of the parameter or parameters to be monitored to ensure that the control technology will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) The Administrator shall determine within 120 calendar days whether an application presents sufficient information to determine nominal efficiency. The Administrator reserves the right to request specific data in addition to the items listed in paragraph (i)(1) of this section.

(3) The Administrator shall determine within 120 calendar days of the submittal of sufficient data whether a control technology shall have a nominal efficiency and the level of that nominal efficiency. If, in the Administrator's judgment, the control technology achieves a level of emission reduction greater than the reference control technology for a particular kind of emission point, the Administrator will publish a FEDERAL REGISTER notice establishing a nominal efficiency for the control technology.

(4) The Administrator may grant conditional permission to take emission credits for use of the control technology on requirements that may be necessary to ensure operation and maintenance to achieve the specified nominal efficiency.

(5) In those cases where the owner or operator is seeking permission to take credit for use of a control technology that is different in use or design from the reference control technology and the different control technology will be used in no more than three applications at a single plant site, the information listed in paragraphs (i)(1)(i) through (i)(1)(iv) of this section can be submitted to the permitting authority for the source for approval instead of the Administrator.

(i) In these instances, use and conditions for use of the control technology can be approved by the permitting authority. The permitting authority shall follow the procedures specified in paragraphs (i)(2) through (i)(4) of this section except that, in these instances, a FEDERAL REGISTER notice is not required to establish the nominal efficiency for the different technology.

(ii) If, in reviewing the submittal, the permitting authority believes the control technology has broad applicability for use by other sources, the permitting authority shall submit the information provided in the application to the Director of the EPA Office of Air Quality Planning and Standards. The Administrator shall review the technology for broad applicability and may publish a FEDERAL REGISTER notice; however, this review shall not affect the permitting authority's approval of the nominal efficiency of the control technology for the specific application.

(6) If, in reviewing an application for a control technology for an emission point, the Administrator or permitting authority determines the control technology is not different in use or design from the reference control technology, the Administrator or permitting authority shall deny the application.

(j) The following procedures shall be used for calculating the efficiency (percentage of reduction) of pollution prevention measures:

(1) A pollution prevention measure is any practice that meets the criteria of paragraphs (j)(1)(i) and (j)(1)(ii) of this section.

(i) A pollution prevention measure is any practice that results in a lesser quantity of organic HAP emissions per unit of product released to the atmosphere prior to out-of-process recycling, treatment, or control of emissions while the same product is produced.

(ii) Pollution prevention measures may include: Substitution of feedstocks that reduce HAP emissions, alterations to the production process to reduce the volume of materials released to the environment, equipment modifications; housekeeping measures, and in-process recycling that returns waste materials directly to production as raw materials. Production cutbacks do not qualify as pollution prevention.

(2) The emission reduction efficiency of pollution prevention measures implemented after November 15, 1990 can be used in calculating the actual emissions from an emission point in the debit and credit equations in paragraphs (g) and (h) of this section.

(i) For pollution prevention measures, the percentage of reduction used in the equations in paragraphs (g)(2) and (g)(3) of this section and paragraphs (h)(2) through (h)(4) of this section is the difference in percentage between the monthly organic HAP emissions for each emission point after the pollution prevention measure for the most recent month versus monthly emissions from the same emission point before the pollution prevention measure, adjusted by the volume of product produced during the two monthly periods.

(ii) The following equation shall be used to calculate the percentage of reduction of a pollution prevention measure for each emission point.

$$\text{Percent reduction} = \frac{\mathrm{E_B} \, \dfrac{\left(E_{pp} \times P_B\right)}{P_{pp}}}{E_B} \times 100\%$$

Where:

Percent reduction = Efficiency of pollution prevention measure (percentage of organic HAP reduction).

E_B = Monthly emissions before the pollution prevention measure, megagrams per month, determined as specified in paragraphs (j)(2)(ii)(A), (j)(2)(ii)(B), and (j)(2)(ii)(C) of this section.

E_{pp} = Monthly emissions after the pollution prevention measure, megagrams per month, as determined for the most recent month, determined as specified in paragraphs (j)(2)(ii)(D) or (j)(2)(ii)(E) of this section.

P_B = Monthly production before the pollution prevention measure, megagrams per month, during the same period over which E_B is calculated.

P_{pp} = Monthly production after the pollution prevention measure, megagrams per month, as determined for the most recent month.

(A) The monthly emissions before the pollution prevention measure, E_B, shall be determined in a manner consistent with the equations and procedures in paragraphs (g)(2), (g)(3), (g)(4), and (g)(5) of this section for miscellaneous process vents, storage vessels, gasoline loading racks, and marine tank vessels.

(B) For wastewater, E_B shall be calculated as follows:

$$E_B = \sum_{i=1}^{n} \left[\left(6.0 * 10^{-8}\right) Q_{Bi} \, H_B \sum_{m=1}^{5} Fe_m HAP_{Bim} \right]$$

where:

n = Number of wastewater streams.

Q_{Bi} = Average flow rate for wastewater stream i before the pollution prevention measure, liters per minute.

H_{Bi} = Number of hours per month that wastewater stream i was discharged before the pollution prevention measure, hours per month.

s = Total number of organic HAP's in wastewater stream i.

Fe_m = Fraction emitted of organic HAP m in wastewater from table 7 of this subpart, dimensionless.

HAP_{Bim} = Average concentration of organic HAP m in wastewater stream i, defined and determined according to paragraph (h)(6)(ii)(A)(*2*) of this section, before the pollution prevention measure, parts per million by weight, as measured before the implementation of the pollution measure.

(C) If the pollution prevention measure was implemented prior to July 14, 1994, records may be used to determine E_B.

(D) The monthly emissions after the pollution prevention measure, E_{pp}, may be determined during a performance test or by a design evaluation and documented engineering calculations. Once an emissions-to-production ratio has been established, the ratio can be used to estimate monthly emissions from monthly production records.

(E) For wastewater, E_{pp} shall be calculated using the following equation:

$$E_{pp} = \sum_{i=1}^{n} \left[\left(6.0 * 10^{-8}\right) Q_{ppi} \, H_{ppi} \sum_{m=1}^{s} Fe_m HAP_{ppim} \right]$$

where n, Q, H, s, Fe_m, and HAP are defined and determined as described in paragraph (j)(2)(ii)(B) of this section except that Q_{ppi}, H_{ppi}, and HAP_{ppim} shall be determined after the pollution prevention measure has been implemented.

(iii) All equations, calculations, test procedures, test results, and other information used to determine the percentage of reduction achieved by a pollution prevention measure for each emission point shall be fully documented.

(iv) The same pollution prevention measure may reduce emissions from multiple emission points. In such cases, the percentage of reduction in emissions for each emission point must be calculated.

(v) For the purposes of the equations in paragraphs (h)(2) through (h)(6) of this section used to calculate credits for emission points controlled more stringently than the reference control technology, the nominal efficiency of a pollution prevention measure is equivalent to the percentage of reduction of the pollution prevention measure. When a pollution prevention measure is used, the owner or operator of a source is not required to apply to the Administrator for a nominal efficiency and is not subject to paragraph (i) of this section.

(k) The owner or operator shall demonstrate that the emissions from the emission points proposed to be included in the average will not result in greater hazard or, at the option of the State or local permitting authority, greater risk to human health or the environment than if the emission points were controlled according to the provisions in §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable.

(1) This demonstration of hazard or risk equivalency shall be made to the satisfaction of the State or local permitting authority.

(i) The State or local permitting authority may require owners and operators to use specific methodologies and procedures for making a hazard or risk determination.

(ii) The demonstration and approval of hazard or risk equivalency may be made according to any guidance that the EPA makes available for use.

(2) Owners and operators shall provide documentation demonstrating the hazard or risk equivalency of their proposed emissions average in their Implementation Plan.

(3) An emissions averaging plan that does not demonstrate an equivalent or lower hazard or risk to the satisfaction of the State or local permitting authority shall not be approved. The State or local permitting authority may require such adjustments to the emissions averaging plan as are necessary in order to ensure that the average will not result in greater hazard or risk to human health or the environment than would result if the emission points were controlled according to §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable.

(4) A hazard or risk equivalency demonstration shall:

(i) Be a quantitative, bona fide chemical hazard or risk assessment;

(ii) Account for differences in chemical hazard or risk to human health or the environment; and

(iii) Meet any requirements set by the State or local permitting authority for such demonstrations.

(l) For periods of excess emissions, an owner or operator may request that the provisions of paragraphs (l)(1) through (l)(4) of this section be followed instead of the procedures in paragraphs (f)(3)(i) and (f)(3)(ii) of this section.

(1) The owner or operator shall notify the Administrator of excess emissions in the Periodic Reports as required in §63.655(g)(6).

(2) The owner or operator shall demonstrate that other types of monitoring data or engineering calculations are appropriate to establish that the control device for the emission point was operating in such a fashion to warrant assigning full or partial credits and debits. This demonstration shall be made to the Administrator's satisfaction, and the Administrator may establish procedures for demonstrating compliance that are acceptable.

(3) The owner or operator shall provide documentation of the period of excess emissions and the other type of monitoring data or engineering calculations to be used to demonstrate that the control device for the emission point was operating in such a fashion to warrant assigning full or partial credits and debits.

(4) The Administrator may assign full or partial credit and debits upon review of the information provided.

[60 FR 43260, Aug. 18, 1995; 60 FR 49976, Sept. 27, 1995; 61 FR 7051, Feb. 23, 1996, as amended at 61 FR 29881, June 12, 1996; 61 FR 33799, June 28, 1996; 74 FR 55686, Oct. 28, 2009; 80 FR 75246, Dec. 1, 2015]

§63.653 Monitoring, recordkeeping, and implementation plan for emissions averaging.

(a) For each emission point included in an emissions average, the owner or operator shall perform testing, monitoring, recordkeeping, and reporting equivalent to that required for Group 1 emission points complying with §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable. The specific requirements for miscellaneous process vents, storage vessels, wastewater, gasoline loading racks, and marine tank vessels are identified in paragraphs (a)(1) through (7) of this section.

(1) The source shall implement the following testing, monitoring, recordkeeping, and reporting procedures for each miscellaneous process vent equipped with a flare, incinerator, boiler, or process heater:

(i) Conduct initial performance tests to determine the percentage of reduction as specified in §63.645 of this subpart and §63.116 of subpart G; and

(ii) Monitor the operating parameters specified in §63.644, as appropriate for the specific control device.

(2) The source shall implement the following procedures for each miscellaneous process vent, equipped with a carbon adsorber, absorber, or condenser but not equipped with a control device:

(i) Determine the flow rate and organic HAP concentration using the methods specified in §63.115 (a)(1) and (a)(2), §63.115 (b)(1) and (b)(2), and §63.115(c)(3) of subpart G; and

(ii) Monitor the operating parameters specified in §63.114 of subpart G, as appropriate for the specific recovery device.

(3) 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 §63.646 and either §63.120 of subpart G or §63.1063 of subpart WW, as applicable; and

(ii) For closed vent systems with control devices, conduct an initial design evaluation as specified in §63.646 and either §63.120(d) of subpart G or §63.985(b) of subpart SS, as applicable.

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

(5) For each marine tank vessel that is controlled, perform the compliance, monitoring, and performance testing, procedures specified in §§63.563, 63.564, and 63.565 of subpart Y of this part.

(6) The source shall implement the following procedures for wastewater emission points, as appropriate to the control techniques:

(i) For wastewater treatment processes, conduct tests as specified in §61.355 of subpart FF of part 60;

(ii) Conduct inspections and monitoring as specified in §§61.343 through 61.349 and §61.354 of 40 CFR part 61, subpart FF.

(7) 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 §§63.643 through 63.645, 63.646 or 63.660, 63.647, 63.650, and 63.651, as applicable, the owner or operator shall establish a site-specific monitoring parameter and shall submit the information specified in §63.655(h)(4) in the Implementation Plan.

(b) Records of all information required to calculate emission debits and credits and records required by §63.655 shall be retained for 5 years.

(c) Notifications of Compliance Status report, Periodic Reports, and other reports shall be submitted as required by §63.655.

(d) Each owner or operator of an existing source who elects to comply with §63.655(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 an owner or operator submits the information specified in paragraph (d)(2) of this section 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 paragraphs (d)(2)(i) through (d)(2)(ix) of this section for all points included in the average.

(i) The identification of all emission points in the planned emissions average and notation of whether each emission point is a Group 1 or Group 2 emission point as defined in §63.641.

(ii) The projected annual emission debits and credits for each emission point and the sum for the emission points involved in the average calculated according to §63.652. The annual projected credits must be greater than the projected debits, as required under §63.652(e)(3).

(iii) The specific control technology or pollution prevention measure that will be used for each emission point included in the average and date of application or expected date of application.

(iv) The specific identification of each emission point affected by a pollution prevention measure. To be considered a pollution prevention measure, the criteria in §63.652(j)(1) must be met. If the same pollution prevention measure reduces or eliminates emissions from multiple emission points in the average, the owner or operator must identify each of these emission points.

(v) A statement that the compliance demonstration, monitoring, inspection, recordkeeping, and reporting provisions in paragraphs (a), (b), and (c) of this section that are applicable to each emission point in the emissions average will be implemented beginning on the date of compliance.

(vi) Documentation of the information listed in paragraphs (d)(2)(vi)(A) through (d)(2)(vi)(D) of this section for each emission point included in the average.

(A) The values of the parameters used to determine whether each emission point in the emissions average is Group 1 or Group 2.

(B) The estimated values of all parameters needed for input to the emission debit and credit calculations in §63.652 (g) and (h). These parameter values or, as appropriate, limited ranges for the parameter values, shall be specified in the source's Implementation Plan as enforceable operating conditions. Changes to these parameters must be reported in the next Periodic Report.

(C) The estimated percentage of reduction if a control technology achieving a lower percentage of reduction than the efficiency of the reference control technology, as defined in §63.641, is or will be applied to the emission point.

(D) The anticipated nominal efficiency if a control technology achieving a greater percentage emission reduction than the efficiency of the reference control technology is or will be applied to the emission point. The procedures in §63.652(i) shall be followed to apply for a nominal efficiency.

(vii) The information specified in §63.655(h)(4) for:

(A) Each miscellaneous process vent controlled by a pollution prevention measure or control technique for which monitoring parameters or inspection procedures are not specified in paragraphs (a)(1) or (a)(2) of this section; and

(B) Each storage vessel controlled by a pollution prevention measure or a control technique other than an internal or external floating roof or a closed vent system with a control device.

(viii) Documentation of the information listed in paragraphs (d)(2)(viii)(A) through (d)(2)(viii)(G) of this section for each process wastewater stream included in the average.

(A) The information used to determine whether the wastewater stream is a Group 1 or Group 2 wastewater stream.

(B) The estimated values of all parameters needed for input to the wastewater emission credit and debit calculations in §63.652(h)(6).

(C) The estimated percentage of reduction if the wastewater stream is or will be controlled using a treatment process or series of treatment processes that achieves an emission reduction less than or equal to the emission reduction specified in table 7 of this subpart.

(D) The estimated percentage of reduction if a control technology achieving less than or equal to 95 percent emission reduction is or will be applied to the vapor stream(s) vented and collected from the treatment processes.

(E) The estimated percentage of reduction if a pollution prevention measure is or will be applied.

(F) The anticipated nominal efficiency if the owner or operator plans to apply for a nominal efficiency under §63.652(i). A nominal efficiency shall be applied for if:

(*1*) A control technology is or will be applied to the wastewater stream and achieves an emission reduction greater than the emission reduction specified in table 7 of this subpart; or

(*2*) A control technology achieving greater than 95 percent emission reduction is or will be applied to the vapor stream(s) vented and collected from the treatment processes.

(G) For each pollution prevention measure, treatment process, or control device used to reduce air emissions of organic HAP from wastewater and for which no monitoring parameters or inspection procedures are specified in §63.647, the information specified in §63.655(h)(4) shall be included in the Implementation Plan.

(ix) Documentation required in §63.652(k) demonstrating the hazard or risk equivalency of the proposed emissions 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 owner or operator submit additional information. Once the Administrator receives sufficient information, the Administrator shall approve, disapprove, or request changes to the plan within 120 calendar days.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29881, June 12, 1996; 63 FR 31361, June 9, 1998; 74 FR 55686, Oct. 28, 2009; 80 FR 75246, Dec. 1, 2015]

§63.654 Heat exchange systems.

(a) Except as specified in paragraph (b) of this section, the owner or operator of a heat exchange system that meets the criteria in §63.640(c)(8) must comply with the requirements of paragraphs (c) through (g) of this section.

(b) A heat exchange system is exempt from the requirements in paragraphs (c) through (g) of this section if all heat exchangers within the heat exchange system either:

(1) Operate with the minimum pressure on the cooling water side at least 35 kilopascals greater than the maximum pressure on the process side; or

(2) Employ an intervening cooling fluid containing less than 5 percent by weight of total organic HAP, as determined according to the provisions of §63.180(d) of this part and table 1 of this subpart, between the process and the cooling water. This intervening fluid must serve to isolate the cooling water from the process fluid and must not be sent through a cooling tower or discharged. For purposes of this section, discharge does not include emptying for maintenance purposes.

(c) The owner or operator must perform monitoring to identify leaks of total strippable volatile organic compounds (VOC) from each heat exchange system subject to the requirements of this subpart according to the procedures in paragraphs (c)(1) through (6) of this section.

(1) *Monitoring locations for closed-loop recirculation heat exchange systems.* For each closed loop recirculating heat exchange system, collect and analyze a sample from the location(s) described in either paragraph (c)(1)(i) or (c)(1)(ii) of this section.

(i) Each cooling tower return line or any representative riser within the cooling tower prior to exposure to air for each heat exchange system.

(ii) Selected heat exchanger exit line(s) so that each heat exchanger or group of heat exchangers within a heat exchange system is covered by the selected monitoring location(s).

(2) *Monitoring locations for once-through heat exchange systems.* For each once-through heat exchange system, collect and analyze a sample from the location(s) described in paragraph (c)(2)(i) of this section. The owner or operator may also elect to collect and analyze an additional sample from the location(s) described in paragraph (c)(2)(ii) of this section.

(i) Selected heat exchanger exit line(s) so that each heat exchanger or group of heat exchangers within a heat exchange system is covered by the selected monitoring location(s). The selected monitoring location may be at a point where discharges from multiple heat exchange systems are combined provided that the combined cooling water flow rate at the monitoring location does not exceed 40,000 gallons per minute.

(ii) The inlet water feed line for a once-through heat exchange system prior to any heat exchanger. If multiple heat exchange systems use the same water feed (*i.e.,* inlet water from the same primary water source), the owner or operator may monitor at one representative location and use the monitoring results for that sampling location for all heat exchange systems that use that same water feed.

(3) *Monitoring method.* Determine the total strippable hydrocarbon concentration (in parts per million by volume (ppmv) as methane) at each monitoring location using the “Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources” Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003 (incorporated by reference—see §63.14) using a flame ionization detector (FID) analyzer for on-site determination as described in Section 6.1 of the Modified El Paso Method.

(4) *Monitoring frequency and leak action level for existing sources.* For a heat exchange system at an existing source, the owner or operator must comply with the monitoring frequency and leak action level as defined in paragraph (c)(4)(i) of this section or comply with the monitoring frequency and leak action level as defined in paragraph (c)(4)(ii) of this section. The owner or operator of an affected heat exchange system may choose to comply with paragraph (c)(4)(i) of this section for some heat exchange systems at the petroleum refinery and comply with paragraph (c)(4)(ii) of this section for other heat exchange systems. However, for each affected heat exchange system, the owner or operator of an affected heat exchange system must elect one monitoring alternative that will apply at all times. If the owner or operator intends to change the monitoring alternative that applies to a heat exchange system, the owner or operator must notify the Administrator 30 days in advance of such a change. All “leaks” identified prior to changing monitoring alternatives must be repaired. The monitoring frequencies specified in paragraphs (c)(4)(i) and (ii) of this section also apply to the inlet water feed line for a once-through heat exchange system, if monitoring of the inlet water feed is elected as provided in paragraph (c)(2)(ii) of this section.

(i) Monitor monthly using a leak action level defined as a total strippable hydrocarbon concentration (as methane) in the stripping gas of 6.2 ppmv.

(ii) Monitor quarterly using a leak action level defined as a total strippable hydrocarbon concentration (as methane) in the stripping gas of 3.1 ppmv unless repair is delayed as provided in paragraph (f) of this section. If a repair is delayed as provided in paragraph (f) of this section, monitor monthly.

(5) *Monitoring frequency and leak action level for new sources.* For a heat exchange system at a new source, the owner or operator must monitor monthly using a leak action level defined as a total strippable hydrocarbon concentration (as methane) in the stripping gas of 3.1 ppmv.

(6) *Leak definition.* A leak is defined as described in paragraph (c)(6)(i) or (c)(6)(ii) of this section, as applicable.

(i) For once-through heat exchange systems for which the inlet water feed is monitored as described in paragraph (c)(2)(ii) of this section, a leak is detected if the difference in the measurement value of the sample taken from a location specified in paragraph (c)(2)(i) of this section and the measurement value of the corresponding sample taken from the location specified in paragraph (c)(2)(ii) of this section equals or exceeds the leak action level.

(ii) For all other heat exchange systems, a leak is detected if a measurement value of the sample taken from a location specified in either paragraph (c)(1)(i), (c)(1)(ii), or (c)(2)(i) of this section equals or exceeds the leak action level.

(d) If a leak is detected, the owner or operator must repair the leak to reduce the measured concentration to below the applicable action level as soon as practicable, but no later than 45 days after identifying the leak, except as specified in paragraphs (e) and (f) of this section. Repair includes re-monitoring at the monitoring location where the leak was identified according to the method specified in paragraph (c)(3) of this section to verify that the measured concentration is below the applicable action level. Actions that can be taken to achieve repair include but are not limited to:

(1) Physical modifications to the leaking heat exchanger, such as welding the leak or replacing a tube;

(2) Blocking the leaking tube within the heat exchanger;

(3) Changing the pressure so that water flows into the process fluid;

(4) Replacing the heat exchanger or heat exchanger bundle; or

(5) Isolating, bypassing, or otherwise removing the leaking heat exchanger from service until it is otherwise repaired.

(e) If the owner or operator detects a leak when monitoring a cooling tower return line under paragraph (c)(1)(i) of this section, the owner or operator may conduct additional monitoring of each heat exchanger or group of heat exchangers associated with the heat exchange system for which the leak was detected as provided under paragraph (c)(1)(ii) of this section. If no leaks are detected when monitoring according to the requirements of paragraph (c)(1)(ii) of this section, the heat exchange system is considered to meet the repair requirements through re-monitoring of the heat exchange system as provided in paragraph (d) of this section.

(f) The owner or operator may delay the repair of a leaking heat exchanger when one of the conditions in paragraph (f)(1) or (f)(2) of this section is met and the leak is less than the delay of repair action level specified in paragraph (f)(3) of this section. The owner or operator must determine if a delay of repair is necessary as soon as practicable, but no later than 45 days after first identifying the leak.

(1) If the repair is technically infeasible without a shutdown and the total strippable hydrocarbon concentration is initially and remains less than the delay of repair action level for all monthly monitoring periods during the delay of repair, the owner or operator may delay repair until the next scheduled shutdown of the heat exchange system. If, during subsequent monthly monitoring, the delay of repair action level is exceeded, the owner or operator must repair the leak within 30 days of the monitoring event in which the leak was equal to or exceeded the delay of repair action level.

(2) If the necessary equipment, parts, or personnel are not available and the total strippable hydrocarbon concentration is initially and remains less than the delay of repair action level for all monthly monitoring periods during the delay of repair, the owner or operator may delay the repair for a maximum of 120 calendar days. The owner or operator must demonstrate that the necessary equipment, parts, or personnel were not available. If, during subsequent monthly monitoring, the delay of repair action level is exceeded, the owner or operator must repair the leak within 30 days of the monitoring event in which the leak was equal to or exceeded the delay of repair action level.

(3) The delay of repair action level is a total strippable hydrocarbon concentration (as methane) in the stripping gas of 62 ppmv. The delay of repair action level is assessed as described in paragraph (f)(3)(i) or (f)(3)(ii) of this section, as applicable.

(i) For once-through heat exchange systems for which the inlet water feed is monitored as described in paragraph (c)(2)(ii) of this section, the delay of repair action level is exceeded if the difference in the measurement value of the sample taken from a location specified in paragraph (c)(2)(i) of this section and the measurement value of the corresponding sample taken from the location specified in paragraph (c)(2)(ii) of this section equals or exceeds the delay of repair action level.

(ii) For all other heat exchange systems, the delay of repair action level is exceeded if a measurement value of the sample taken from a location specified in either paragraphs (c)(1)(i), (c)(1)(ii), or (c)(2)(i) of this section equals or exceeds the delay of repair action level.

(g) To delay the repair under paragraph (f) of this section, the owner or operator must record the information in paragraphs (g)(1) through (4) of this section.

(1) The reason(s) for delaying repair.

(2) A schedule for completing the repair as soon as practical.

(3) The date and concentration of the leak as first identified and the results of all subsequent monthly monitoring events during the delay of repair.

(4) An estimate of the potential strippable hydrocarbon emissions from the leaking heat exchange system or heat exchanger for each required delay of repair monitoring interval following the procedures in paragraphs (g)(4)(i) through (iv) of this section.

(i) Determine the leak concentration as specified in paragraph (c) of this section and convert the stripping gas leak concentration (in ppmv as methane) to an equivalent liquid concentration, in parts per million by weight (ppmw), using equation 7-1 from “Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources” Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003 (incorporated by reference—see §63.14) and the molecular weight of 16 grams per mole (g/mol) for methane.

(ii) Determine the mass flow rate of the cooling water at the monitoring location where the leak was detected. If the monitoring location is an individual cooling tower riser, determine the total cooling water mass flow rate to the cooling tower. Cooling water mass flow rates may be determined using direct measurement, pump curves, heat balance calculations, or other engineering methods. Volumetric flow measurements may be used and converted to mass flow rates using the density of water at the specific monitoring location temperature or using the default density of water at 25 degrees Celsius, which is 997 kilograms per cubic meter or 8.32 pounds per gallon.

(iii) For delay of repair monitoring intervals prior to repair of the leak, calculate the potential strippable hydrocarbon emissions for the leaking heat exchange system or heat exchanger for the monitoring interval by multiplying the leak concentration in the cooling water, ppmw, determined in (g)(4)(i) of this section, by the mass flow rate of the cooling water determined in (g)(4)(ii) of this section and by the duration of the delay of repair monitoring interval. The duration of the delay of repair monitoring interval is the time period starting at midnight on the day of the previous monitoring event or at midnight on the day the repair would have had to be completed if the repair had not been delayed, whichever is later, and ending at midnight of the day the of the current monitoring event.

(iv) For delay of repair monitoring intervals ending with a repaired leak, calculate the potential strippable hydrocarbon emissions for the leaking heat exchange system or heat exchanger for the final delay of repair monitoring interval by multiplying the duration of the final delay of repair monitoring interval by the leak concentration and cooling water flow rates determined for the last monitoring event prior to the re-monitoring event used to verify the leak was repaired. The duration of the final delay of repair monitoring interval is the time period starting at midnight of the day of the last monitoring event prior to re-monitoring to verify the leak was repaired and ending at the time of the re-monitoring event that verified that the leak was repaired.

[74 FR 55686, Oct. 28, 2009, as amended at 75 FR 37731, June 30, 2010; 78 FR 37146, June 20, 2013]

§63.655 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to the wastewater provisions in §63.647 shall comply with the recordkeeping and reporting provisions in §§61.356 and 61.357 of 40 CFR part 61, subpart FF unless they are complying with the wastewater provisions specified in paragraph (o)(2)(ii) of §63.640. There are no additional reporting and recordkeeping requirements for wastewater under this subpart unless a wastewater stream is included in an emissions average. Recordkeeping and reporting for emissions averages are specified in §63.653 and in paragraphs (f)(5) and (g)(8) of this section.

(b) Each owner or operator subject to the gasoline loading rack provisions in §63.650 shall comply with the recordkeeping and reporting provisions in §63.428 (b) and (c), (g)(1), (h)(1) through (h)(3), and (k) of subpart R. 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 §63.653 and in paragraphs (f)(5) and (g)(8) of this section.

(c) Each owner or operator subject to the marine tank vessel loading operation standards in §63.651 shall comply with the recordkeeping and reporting provisions in §§63.567(a) and 63.567(c) through (k) of subpart Y. These requirements are summarized in table 5 of this subpart. There are no additional reporting and recordkeeping requirements for marine tank vessel loading operations under this subpart unless marine tank vessel loading operations are included in an emissions average. Recordkeeping and reporting for emissions averages are specified in §63.653 and in paragraphs (f)(5) and (g)(8) of this section.

(d) Each owner or operator subject to the equipment leaks standards in §63.648 shall comply with the recordkeeping and reporting provisions in paragraphs (d)(1) through (d)(6) of this section.

(1) Sections 60.486 and 60.487 of subpart VV of part 60 except as specified in paragraph (d)(1)(i) of this section; or §§63.181 and 63.182 of subpart H of this part except for §§63.182(b), (c)(2), and (c)(4).

(i) The signature of the owner or operator (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.

(ii) [Reserved]

(2) The Notification of Compliance Status report required by §63.182(c) of subpart H and the initial semiannual report required by §60.487(b) of 40 CFR part 60, subpart VV shall be submitted within 150 days of the compliance date specified in §63.640(h); the requirements of subpart H of this part are summarized in table 3 of this subpart.

(3) An owner or operator who determines that a compressor qualifies for the hydrogen service exemption in §63.648 shall also keep a record of the demonstration required by §63.648.

(4) An owner or operator must keep a list of identification numbers for valves that are designated as leakless per §63.648(c)(10).

(5) An owner or operator 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) An owner or operator must keep a list of reciprocating pumps and compressors determined to be exempt from seal requirements as per §§63.648 (f) and (i).

(e) Each owner or operator of a source subject to this subpart shall submit the reports listed in paragraphs (e)(1) through (e)(3) of this section except as provided in paragraph (h)(5) of this section, and shall keep records as described in paragraph (i) of this section.

(1) A Notification of Compliance Status report as described in paragraph (f) of this section;

(2) Periodic Reports as described in paragraph (g) of this section; and

(3) Other reports as described in paragraph (h) of this section.

(f) Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status report within 150 days after the compliance dates specified in §63.640(h) with the exception of Notification of Compliance Status reports submitted to comply with §63.640(l)(3) and for storage vessels subject to the compliance schedule specified in §63.640(h)(2). Notification of Compliance Status reports required by §63.640(l)(3) and for storage vessels subject to the compliance dates specified in §63.640(h)(2) shall be submitted according to paragraph (f)(6) of this section. 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 §63.640(h), a separate Notification of Compliance Status report is not required within 150 days after the compliance dates specified in §63.640(h). If an owner or operator submits the information specified in paragraphs (f)(1) through (5) of this section 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 owner or operator 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 §63.640(h).

(1) The Notification of Compliance Status report shall include the information specified in paragraphs (f)(1)(i) through (viii) of this section.

(i) For storage vessels, this report shall include the information specified in paragraphs (f)(1)(i)(A) through (f)(1)(i)(D) of this section.

(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 paragraphs (f)(1)(i)(A)(*1*) through (*3*) of this section. 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 §63.640(h)(2) or to comply with §63.640(l)(3).

(*1*) For each Group 1 storage vessel complying with §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).

(*2*) For storage vessels subject to the compliance schedule specified in §63.640(h)(2) that are not complying with §63.646, the anticipated compliance date.

(*3*) For storage vessels subject to the compliance schedule specified in §63.640(h)(2) that are complying with §63.646 and the Group 1 storage vessels described in §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 §63.646 or §63.660, the owner or operator shall submit:

(*1*) 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

(*2*) The design evaluation documentation specified in §63.120(d)(1)(i) of subpart G or §63.985(b)(1)(i) of subpart SS (as applicable), if the owner or operator elects to prepare a design evaluation; or

(*3*) If the owner or operator 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 owner or operator shall submit:

(*1*) 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.

(*2*) 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 owner or operator shall submit:

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

(*2*) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by §63.120(e) of subpart G or §63.987(b) of subpart SS or §63.670(h), as applicable; and

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

(ii) For miscellaneous process vents, identification of each miscellaneous process vent subject to this subpart, whether the process vent is Group 1 or Group 2, and the method of compliance for each Group 1 miscellaneous process vent that is not included in an emissions average (e.g., use of a flare or other control device meeting the requirements of §63.643(a)).

(iii) For miscellaneous process vents controlled by control devices required to be tested under §63.645 of this subpart and §63.116(c) of subpart G of this part, performance test results including the information in paragraphs (f)(1)(iii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in §63.645 and that the test conditions are representative of current operating conditions.

(A) The percentage of reduction of organic HAP's or TOC, or the outlet concentration of organic HAP's or TOC (parts per million by volume on a dry basis corrected to 3 percent oxygen), determined as specified in §63.116(c) of subpart G of this part; and

(B) The value of the monitored parameters specified in table 10 of this subpart, or a site-specific parameter approved by the permitting authority, averaged over the full period of the performance test,

(iv) For miscellaneous process vents controlled by flares, initial compliance test results including the information in paragraphs (f)(1)(iv)(A) and (B) of this section.

(A) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by §§63.645 and 63.116(a) of subpart G or §63.670(h), as applicable; and

(B) A statement of whether a flame was present at the pilot light over the full period of the compliance determination.

(v) For equipment leaks complying with §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 §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.

(vi) For each heat exchange system, identification of the heat exchange systems that are subject to the requirements of this subpart. For heat exchange systems at existing sources, the owner or operator shall indicate whether monitoring will be conducted as specified in §63.654(c)(4)(i) or §63.654(c)(4)(ii).

(vii) For pressure relief devices in organic HAP service subject to the requirements in §63.648(j)(3)(i) and (ii), this report shall include the information specified in paragraphs (f)(1)(vii)(A) and (B) of this section.

(A) A description of the monitoring system to be implemented, including the relief devices and process parameters to be monitored, and a description of the alarms or other methods by which operators will be notified of a pressure release.

(B) A description of the prevention measures to be implemented for each affected pressure relief device.

(viii) For each delayed coking unit, identification of whether the unit is an existing affected source or a new affected source and whether monitoring will be conducted as specified in §63.657(b) or (c).

(2) If initial performance tests are required by §§63.643 through 63.653, the Notification of Compliance Status report shall include one complete test report for each test method used for a particular source. On and after February 1, 2016, performance tests shall be submitted according to paragraph (h)(9) of this section.

(i) For additional tests performed using the same method, the results specified in paragraph (f)(1) of this section 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 §§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 §63.120(d) of subpart G or §63.985(b) of subpart SS for storage vessels or §63.644 for miscellaneous process vents, the Notification of Compliance Status report shall include the information in paragraphs (f)(3)(i) through (iii) of this section.

(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 §63.652(g) and (h), calculated or measured according to the procedures in §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 §63.640.

(6) Notification of Compliance Status reports required by §63.640(l)(3) and for storage vessels subject to the compliance dates specified in §63.640(h)(2) 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 paragraph (g) of this section. The Notification of Compliance Status report shall include the information specified in paragraphs (f)(1) through (f)(5) of this section. 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 an owner or operator submits the information specified in paragraphs (f)(1) through (f)(5)

of this section at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating and resubmitting the previously submitted information.

(g) The owner or operator 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 information specified in paragraphs (g)(1) through (7) of this section or paragraphs (g)(9) through (14) of this section is collected. 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 events identified in paragraphs (g)(1) through (7) of this section or paragraphs (g)(9) through (14) of this section occurred during the 6-month period unless emissions averaging is utilized. Quarterly reports must be submitted for emission points included in emission averages, as provided in paragraph (g)(8) of this section. An owner or operator may submit reports required by other regulations in place of or as part of the Periodic Report required by this paragraph (g) if the reports contain the information required by paragraphs (g)(1) through (14) of this section.

(1) For storage vessels, Periodic Reports shall include the information specified for Periodic Reports in paragraphs (g)(2) through (5) of this section. Information related to gaskets, slotted membranes, and sleeve seals is not required for storage vessels that are part of an existing source complying with §63.646.

(2) *Internal floating roofs.* (i) An owner or operator who elects to comply with §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 §63.120(a) of subpart G in which a failure is detected in the control equipment.

(A) For vessels for which annual inspections are required under §63.120(a)(2)(i) or (a)(3)(ii) of subpart G, the specifications and requirements listed in paragraphs (g)(2)(i)(A)(*1*) through (*3*) of this section apply.

(*1*) 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.

(*2*) Except as provided in paragraph (g)(2)(i)(A)(*3*) of this section, 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.

(*3*) If an extension is utilized in accordance with §63.120(a)(4) of subpart G, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in §63.120(a)(4) of subpart G; and describe the date the storage vessel was emptied and the nature of and date the repair was made.

(B) For vessels for which inspections are required under §63.120(a)(2)(ii), (a)(3)(i), or (a)(3)(iii) of subpart G (*i.e.*, internal inspections), the specifications and requirements listed in paragraphs (g)(2)(i)(B)(*1*) and (*2*) of this section apply.

(*1*) 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.

(*2*) 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.

(ii) An owner or operator who elects to comply with §63.660 by using a fixed roof and an internal floating roof shall submit the results of each inspection conducted in accordance with §63.1063(c)(1), (d)(1), and (d)(2) of subpart WW in which a failure is detected in the control equipment. For vessels for which inspections are required under §63.1063(c) and (d), the specifications and requirements listed in paragraphs (g)(2)(ii)(A) through (C) of this section apply.

(A) A failure is defined in §63.1063(d)(1) of subpart WW.

(B) Each Periodic Report shall include a copy of the inspection record required by §63.1065(b) of subpart WW when a failure occurs.

(C) An owner or operator who elects to use an extension in accordance with §63.1063(e)(2) of subpart WW shall, in the next Periodic Report, submit the documentation required by §63.1063(e)(2).

(3) *External floating roofs.* (i) An owner or operator who elects to comply with §63.646 by using an external floating roof shall meet the periodic reporting requirements specified in paragraphs (g)(3)(i)(A) through (C) of this section.

(A) The owner or operator shall submit, as part of the Periodic Report, documentation of the results of each seal gap measurement made in accordance with §63.120(b) of subpart G in which the seal and seal gap requirements of §63.120(b)(3), (4), (5), or (6) of subpart G are not met. This documentation shall include the information specified in paragraphs (g)(3)(i)(A)(*1*) through (*4*) of this section.

(*1*) The date of the seal gap measurement.

(*2*) The raw data obtained in the seal gap measurement and the calculations described in §63.120(b)(3) and (4) of subpart G.

(*3*) A description of any seal condition specified in §63.120(b)(5) or (6) of subpart G that is not met.

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

(B) If an extension is utilized in accordance with §63.120(b)(7)(ii) or (b)(8) of subpart G, the owner or operator shall, in the next Periodic Report, identify the vessel; include the documentation specified in §63.120(b)(7)(ii) or (b)(8) of subpart G, as applicable; and describe the date the vessel was emptied and the nature of and date the repair was made.

(C) The owner or operator shall submit, as part of the Periodic Report, documentation of any failures that are identified during visual inspections required by §63.120(b)(10) of subpart G. This documentation shall meet the specifications and requirements in paragraphs (g)(3)(i)(C)(*1*) and (*2*) of this section.

(*1*) 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.

(*2*) 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.

(ii) An owner or operator who elects to comply with §63.660 by using an external floating roof shall meet the periodic reporting requirements specified in paragraphs (g)(3)(ii)(A) and (B) of this section.

(A) For vessels for which inspections are required under §63.1063(c)(2), (d)(1), and (d)(3) of subpart WW, the owner or operator shall submit, as part of the Periodic Report, a copy of the inspection record required by §63.1065(b) of subpart WW when a failure occurs. A failure is defined in §63.1063(d)(1).

(B) An owner or operator who elects to use an extension in accordance with §63.1063(e)(2) or (c)(2)(iv)(B) of subpart WW shall, in the next Periodic Report, submit the documentation required by those paragraphs.

(4) [Reserved]

(5) An owner or operator who elects to comply with §63.646 or §63.660 by installing a closed vent system and control device shall submit, as part of the next Periodic Report, the information specified in paragraphs (g)(5)(i) through (v) of this section, as applicable.

(i) The Periodic Report shall include the information specified in paragraphs (g)(5)(i)(A) and (B) of this section for those planned routine maintenance operations that would require the control device not to meet the requirements of either §63.119(e)(1) or (2) of subpart G, §63.985(a) and (b) of subpart SS, or §63.670, 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 either §63.119(e)(1) or (2) of subpart G, §63.985(a) and (b) of subpart SS, or §63.670, 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 prior to January 30, 2019 and prior to electing to comply with the requirements in §63.670, the Periodic Report shall describe each occurrence when the flare does not meet the general control device requirements specified in §63.11(b) of subpart A and shall include: Identification of the flare that does not meet the general requirements specified in §63.11(b) of subpart A, and reasons the flare did not meet the general requirements specified in §63.11(b) of subpart A.

(iv) If a flare is used on or after the date for which compliance with the requirements in §63.670 is elected, which can be no later than January 30, 2019, the Periodic Report shall include the items specified in paragraph (g)(11) of this section.

(v) An owner or operator who elects to comply with §63.660 by installing an alternate control device as described in §63.1064 of subpart WW shall submit, as part of the next Periodic Report, a written application as described in §63.1066(b)(3) of subpart WW.

(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 (i)(3) (i) and (ii) of this section are available for less than 75 percent of the operating hours.

(D) For data compression systems under paragraph (h)(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) For periods in closed vent systems when a Group 1 miscellaneous process vent stream was detected in the bypass line or diverted from the control device and either directly to the atmosphere or to a control device that does not comply with the requirements in §63.643(a), report the date, time, duration, estimate of the volume of gas, the concentration of organic HAP in the gas and the resulting mass emissions of organic HAP that bypassed the control device. For periods when the flow indicator is not operating, report the date, time, and duration.

(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 identification of the source tested, the date of the test, the percentage of emissions reduction or outlet pollutant concentration reduction (whichever is needed to determine compliance) for each run and for the average of all runs, and the values of the monitored operating parameters.

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

(8) The owner or operator 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 §63.640.

(ii) The quarterly reports shall include:

(A) The information specified in this paragraph and in paragraphs (g)(2) through (g)(7) of this section for all storage vessels and miscellaneous process vents included in an emissions average;

(B) The information required to be reported by §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) The information required to be reported by §63.567(e)(4) and (j)(3) of subpart Y for each marine tank vessel loading operation included in an emissions average, unless the information has already been submitted in a separate report;

(D) 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;

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

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

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

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

(iii) Every fourth quarterly report shall include the following:

(A) A demonstration that annual credits are greater than or equal to annual debits as required by §63.652(e)(3); and

(B) A certification of compliance with all the emissions averaging provisions in §63.652 of this subpart.

(9) For heat exchange systems, Periodic Reports must include the following information:

(i) The number of heat exchange systems at the plant site subject to the monitoring requirements in §63.654.

(ii) The number of heat exchange systems at the plant site found to be leaking.

(iii) For each monitoring location where the total strippable hydrocarbon concentration was determined to be equal to or greater than the applicable leak definitions specified in §63.654(c)(6), identification of the monitoring location (e.g., unique monitoring location or heat exchange system ID number), the measured total strippable hydrocarbon concentration, the date the leak was first identified, and, if applicable, the date the source of the leak was identified;

(iv) For leaks that were repaired during the reporting period (including delayed repairs), identification of the monitoring location associated with the repaired leak, the total strippable hydrocarbon concentration measured during re-monitoring to verify repair, and the re-monitoring date (*i.e.*, the effective date of repair); and

(v) For each delayed repair, identification of the monitoring location associated with the leak for which repair is delayed, the date when the delay of repair began, the date the repair is expected to be completed (if the leak is not repaired during the reporting period), the total strippable hydrocarbon concentration and date of each monitoring event conducted on the delayed repair during the reporting period, and an estimate of the potential strippable hydrocarbon emissions over the reporting period associated with the delayed repair.

(10) For pressure relief devices subject to the requirements §63.648(j), Periodic Reports must include the information specified in paragraphs (g)(10)(i) through (iii) of this section.

(i) For pressure relief devices in organic HAP gas or vapor service, pursuant to §63.648(j)(1), report any instrument reading of 500 ppm or greater.

(ii) For pressure relief devices in organic HAP gas or vapor service subject to §63.648(j)(2), report confirmation that any monitoring required to be done during the reporting period to show compliance was conducted.

(iii) For pressure relief devices in organic HAP service subject to §63.648(j)(3), report each pressure release to the atmosphere, including duration of the pressure release and estimate of the mass quantity of each organic HAP released, and the results of any root cause analysis and corrective action analysis completed during the reporting period, including the corrective actions implemented during the reporting period and, if applicable, the implementation schedule for planned corrective actions to be implemented subsequent to the reporting period.

(11) For flares subject to §63.670, Periodic Reports must include the information specified in paragraphs (g)(11)(i) through (iv) of this section.

(i) Records as specified in paragraph (i)(9)(i) of this section for each 15-minute block during which there was at least one minute when regulated material is routed to a flare and no pilot flame is present.

(ii) Visible emission records as specified in paragraph (i)(9)(ii)(C) of this section for each period of 2 consecutive hours during which visible emissions exceeded a total of 5 minutes.

(iii) The 15-minute block periods for which the applicable operating limits specified in §63.670(d) through (f) are not met. Indicate the date and time for the period, the net heating value operating parameter(s) determined following the methods in §63.670(k) through (n) as applicable.

(iv) For flaring events meeting the criteria in §63.670(o)(3):

(A) The start and stop time and date of the flaring event.

(B) The length of time for which emissions were visible from the flare during the event.

(C) The periods of time that the flare tip velocity exceeds the maximum flare tip velocity determined using the methods in §63.670(d)(2) and the maximum 15-minute block average flare tip velocity recorded during the event.

(D) Results of the root cause and corrective actions analysis completed during the reporting period, including the corrective actions implemented during the reporting period and, if applicable, the implementation schedule for planned corrective actions to be implemented subsequent to the reporting period.

(12) For delayed coking units, the Periodic Report must include the information specified in paragraphs (g)(12)(i) through (iv) of this section.

(i) For existing source delayed coking units, any 60-cycle average exceeding the applicable limit in §63.657(a)(1).

(ii) For new source delayed coking units, any direct venting event exceeding the applicable limit in §63.657(a)(2).

(iii) The total number of double quenching events performed during the reporting period.

(iv) For each double quenching draining event when the drain water temperature exceeded 210 °F, report the drum, date, time, the coke drum vessel pressure or temperature, as applicable, when pre-vent draining was initiated, and the maximum drain water temperature during the pre-vent draining period.

(13) For maintenance vents subject to the requirements in §63.643(c), Periodic Reports must include the information specified in paragraphs (g)(13)(i) through (iv) of this section for any release exceeding the applicable limits in §63.643(c)(1). For the purposes of this reporting requirement, owners or operators complying with §63.643(c)(1)(iv) must report each venting event for which the lower explosive limit is 20 percent or greater.

(i) Identification of the maintenance vent and the equipment served by the maintenance vent.

(ii) The date and time the maintenance vent was opened to the atmosphere.

(iii) The lower explosive limit, vessel pressure, or mass of VOC in the equipment, as applicable, at the start of atmospheric venting. If the 5 psig vessel pressure option in §63.643(c)(1)(ii) was used and active purging was initiated while the lower explosive limit was 10 percent or greater, also include the lower explosive limit of the vapors at the time active purging was initiated.

(iv) An estimate of the mass of organic HAP released during the entire atmospheric venting event.

(14) Any changes in the information provided in a previous Notification of Compliance Status report.

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

(1) [Reserved]

(2) For storage vessels, notifications of inspections as specified in paragraphs (h)(2)(i) and (ii) of this section.

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

(A) Except as provided in paragraphs (h)(2)(i) (B) and (C) of this section, the owner or operator 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 paragraph (h)(2)(i)(C) of this section, if the internal inspection required by §63.120(a)(2), (a)(3), or (b)(10) of subpart G or §63.1063(d)(1) of subpart WW is not planned and the owner or operator could not have known about the inspection 30 calendar days in advance of refilling the vessel with organic HAP, the owner or operator 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 this section 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 this section, or sooner than 7 days after submitting the notification required by paragraph (h)(2)(i)(B) of this section 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 owner or operator 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 §63.120(b)(1) or (2) of subpart G or §63.1062(d)(3) of subpart WW. 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 §63.652(h).

(4) The owner or operator who requests approval to monitor a different parameter than those listed in §63.644 for miscellaneous process vents or who is required by §63.653(a)(8) to establish a site-specific monitoring parameter for a point in an emissions average shall submit the information specified in paragraphs (h)(4)(i) through (h)(4)(iii) of this section. For new or reconstructed sources, the information shall be submitted with the application for approval of construction or reconstruction required by §63.5(d) of subpart A and for existing sources, and the information shall be submitted no later than 18 months prior to the compliance date. The information may be submitted in an operating permit application, in an amendment to an operating permit application, or in a separate submittal.

(i) A description of the parameter(s) to be monitored to determine whether excess emissions occur and an explanation of the criteria used to select the parameter(s).

(ii) A description of the methods and procedures that will be used to demonstrate that the parameter can be used to determine excess emissions and the schedule for this demonstration. The owner or operator must certify that they will establish a range for the monitored parameter as part of the Notification of Compliance Status report required in paragraphs (e) and (f) of this section.

(iii) The frequency and content of monitoring, recording, and reporting if: monitoring and recording are not continuous; or if periods of excess emissions, as defined in paragraph (g)(6) of this section, will not be identified in Periodic Reports required under paragraphs (e) and (g) of this section. The rationale for the proposed monitoring, recording, and reporting system shall be included.

(5) An owner or operator may request approval to use alternatives to the continuous operating parameter monitoring and recordkeeping provisions listed in paragraph (i) of this section.

(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 paragraphs (h)(5)(iii) through (h)(5)(iv) of this section, as applicable.

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

(iii) An owner or operator may 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 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) You must maintain a record of the 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 demonstrations that they system meets all criteria of paragraph (h)(5)(iii)(A) of this section.

(iv) An owner or operator may request approval to use other alternative monitoring systems according to the procedures specified in §63.8(f) of subpart A of this part.

(6) The owner or operator shall submit the information specified in paragraphs (h)(6)(i) through (h)(6)(iii) of this section, 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 §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.

(7) The owner or operator of a heat exchange system at an existing source must notify the Administrator at least 30 calendar days prior to changing from one of the monitoring options specified in §63.654(c)(4) to the other.

(8) For fenceline monitoring systems subject to §63.658, within 45 calendar days after the end of each reporting period, each owner or operator shall submit the following information to the EPA's Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The owner or operator need not transmit these data prior to obtaining 12 months of data.

(i) Individual sample results for each monitor for each sampling period during the quarterly reporting period. For the first reporting period and for any period in which a passive monitor is added or moved, the owner or operator shall report the coordinates of all of the passive monitor locations. The owner or operator shall determine the coordinates using an instrument with an accuracy of at least 3 meters. Coordinates shall be in decimal degrees with at least five decimal places.

(ii) The biweekly annual average concentration difference (Δc) values for benzene for the quarterly reporting period.

(iii) Notation for each biweekly value that indicates whether background correction was used, all measurements in the sampling period were below detection, or whether an outlier was removed from the sampling period data set.

(9) On and after February 1, 2016, if required to submit the results of a performance test or CEMS performance evaluation, the owner or operator shall submit the results according to the procedures in paragraphs (h)(9)(i) and (ii) of this section.

(i) Within 60 days after the date of completing each performance test as required by this subpart, the owner or operator shall submit the results of the performance tests following the procedure specified in either paragraph (h)(9)(i)(A) or (B) of this section.

(A) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*) at the time of the test, the owner or operator must submit the results of the performance test to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If an owner or operator claims that some of the performance test information being submitted is confidential business information (CBI), the owner or operator must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic storage media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (h)(9)(i)(A).

(B) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, the owner or operator must submit the results of the performance test to the Administrator at the appropriate address listed in §63.13.

(ii) Within 60 days after the date of completing each CEMS performance evaluation as required by this subpart, the owner or operator must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(9)(ii)(A) or (B) of this section.

(A) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, the owner or operator must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If an owner or operator claims that some of the performance evaluation information being submitted is CBI, the owner or operator must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic storage media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (h)(9)(ii)(A).

(B) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, the owner or operator must submit the results of the performance evaluation to the Administrator at the appropriate address listed in §63.13.

(i) *Recordkeeping.* Each owner or operator of a source 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 paragraphs (i)(1) through (12) of this section. 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, flash drive, floppy disk, magnetic tape, or microfiche.

(1) Each owner or operator subject to the storage vessel provisions in §63.646 shall keep the records specified in §63.123 of subpart G except as specified in paragraphs (i)(1)(i) through (iv) of this section. Each owner or operator subject to the storage vessel provisions in §63.660 shall keep records as specified in paragraphs (i)(1)(v) and (vi) of this section.

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

(ii) All references to §63.122 in §63.123 of subpart G shall be replaced with §63.655(e).

(iii) All references to §63.150 in §63.123 of subpart G of this part shall be replaced with §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.

(v) Each owner or operator of a Group 1 storage vessel subject to the provisions in §63.660 shall keep records as specified in §63.1065 or §63.998, as applicable.

(vi) Each owner or operator of a Group 2 storage vessel shall keep the records specified in §63.1065(a) of subpart WW. 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 owner or operator required to report the results of performance tests under paragraphs (f) and (g)(7) of this section shall retain a record of all reported results as well as a complete test report, as described in paragraph (f)(2)(ii) of this section for each emission point tested.

(3) Each owner or operator required to continuously monitor operating parameters under §63.644 for miscellaneous process vents or under §§63.652 and 63.653 for emission points in an emissions average shall keep the records specified in paragraphs (i)(3)(i) through (i)(3)(v) of this section unless an alternative recordkeeping system has been requested and approved under paragraph (h) of this section.

(i) The monitoring system shall measure data values at least once every hour.

(ii) The owner or operator shall record either:

(A) Each measured data value; or

(B) Block average values for 1 hour or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(iii) Daily average values of each continuously monitored parameter shall be calculated for each operating day and retained for 5 years except as specified in paragraph (i)(3)(iv) of this section.

(A) The daily average shall be calculated as the average of all values for a monitored parameter recorded during the operating day. The average shall cover a 24-hour period if operation is continuous, or the number of hours of operation per day if operation is not continuous.

(B) The operating day shall be the period defined in the Notification of Compliance Status report. It may be from midnight to midnight or another daily period.

(iv) If all recorded values for a monitored parameter during an operating day are within the range established in the Notification of Compliance Status report, the owner or operator may record that all values were within the range and retain this record for 5 years rather than calculating and recording a daily average for that day. For these days, the records required in paragraph (i)(3)(ii) of this section shall also be retained for 5 years.

(v) Monitoring data recorded during periods of monitoring system breakdowns, repairs, calibration checks, and zero (low-level) and high-level adjustments shall not be included in any average computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating.

(4) For each closed vent system that contains bypass lines that could divert a vent stream away from the control device and either directly to the atmosphere or to a control device that does not comply with the requirements in §63.643(a), the owner or operator shall keep a record of the information specified in either paragraph (i)(4)(i) or (ii) of this section, as applicable.

(i) The owner or operator shall maintain records of periods when flow was detected in the bypass line, including the date and time and the duration of the flow in the bypass line. For each flow event, the owner or operator shall maintain records sufficient to determine whether or not the detected flow included flow of a Group 1 miscellaneous process vent stream requiring control. For periods when the Group 1 miscellaneous process vent stream requiring control is diverted from the control device and released either directly to the atmosphere or to a control device that does not comply with the requirements in §63.643(a), the owner or operator shall include an estimate of the volume of gas, the concentration of organic HAP in the gas and the resulting emissions of organic HAP that bypassed the control device using process knowledge and engineering estimates.

(ii) Where a seal mechanism is used to comply with §63.644(c)(2), hourly records of flow are not required. In such cases, the owner or operator shall record the date that the monthly visual inspection of the seals or closure mechanisms is completed. The owner or operator shall also record the occurrence of all periods when the seal or closure mechanism is broken, the bypass line valve position has changed or the key for a lock-and-key type lock has been checked out. The owner or operator shall include an estimate of the volume of gas, the concentration of organic HAP in the gas and the resulting mass emissions of organic HAP from the Group 1 miscellaneous process vent stream requiring control that bypassed the control device or records sufficient to demonstrate that there was no flow of a Group 1 miscellaneous process vent stream requiring control during the period.

(5) The owner or operator of a heat exchange system subject to this subpart shall comply with the recordkeeping requirements in paragraphs (i)(5)(i) through (v) of this section and retain these records for 5 years.

(6) All other information required to be reported under paragraphs (a) through (h) of this section shall be retained for 5 years.

(7) Each owner or operator subject to the delayed coking unit decoking operations provisions in §63.657 must maintain records specified in paragraphs (i)(7)(i) through (iii) of this section.

(i) The average pressure or temperature, as applicable, for the 5-minute period prior to venting to the atmosphere, draining, or deheading the coke drum for each cooling cycle for each coke drum.

(ii) If complying with the 60-cycle rolling average, each 60-cycle rolling average pressure or temperature, as applicable, considering all coke drum venting events in the existing affected source.

(iii) For double-quench cooling cycles:

(A) The date, time and duration of each pre-vent draining event.

(B) The pressure or temperature of the coke drum vessel, as applicable, for the 15 minute period prior to the pre-vent draining.

(C) The drain water temperature at 1-minute intervals from the start of pre-vent draining to the complete closure of the drain valve.

(8) For fenceline monitoring systems subject to §63.658, each owner or operator shall keep the records specified in paragraphs (i)(8)(i) through (x) of this section on an ongoing basis.

(i) Coordinates of all passive monitors, including replicate samplers and field blanks, and if applicable, the meteorological station. The owner or operator shall determine the coordinates using an instrument with an accuracy of at least 3 meters. The coordinates shall be in decimal degrees with at least five decimal places.

(ii) The start and stop times and dates for each sample, as well as the tube identifying information.

(iii) Sampling period average temperature and barometric pressure measurements.

(iv) For each outlier determined in accordance with Section 9.2 of Method 325A of appendix A of this part, the sampler location of and the concentration of the outlier and the evidence used to conclude that the result is an outlier.

(v) For samples that will be adjusted for a background, the location of and the concentration measured simultaneously by the background sampler, and the perimeter samplers to which it applies.

(vi) Individual sample results, the calculated Δc for benzene for each sampling period and the two samples used to determine it, whether background correction was used, and the annual average Δc calculated after each sampling period.

(vii) Method detection limit for each sample, including co-located samples and blanks.

(viii) Documentation of corrective action taken each time the action level was exceeded.

(ix) Other records as required by Methods 325A and 325B of appendix A of this part.

(x) If a near-field source correction is used as provided in §63.658(i), records of hourly meteorological data, including temperature, barometric pressure, wind speed and wind direction, calculated daily unit vector wind direction and daily sigma theta, and other records specified in the site-specific monitoring plan.

(9) For each flare subject to §63.670, each owner or operator shall keep the records specified in paragraphs (i)(9)(i) through (xii) of this section up-to-date and readily accessible, as applicable.

(i) Retain records of the output of the monitoring device used to detect the presence of a pilot flame as required in §63.670(b) for a minimum of 2 years. Retain records of each 15-minute block during which there was at least one minute that no pilot flame is present when regulated material is routed to a flare for a minimum of 5 years.

(ii) Retain records of daily visible emissions observations or video surveillance images required in §63.670(h) as specified in the paragraphs (i)(9)(ii)(A) through (C), as applicable, for a minimum of 3 years.

(A) If visible emissions observations are performed using Method 22 at 40 CFR part 60, appendix A-7, the record must identify whether the visible emissions observation was performed, the results of each observation, total duration of observed visible emissions, and whether it was a 5-minute or 2-hour observation. If the owner or operator performs visible emissions observations more than one time during a day, the record must also identify the date and time of day each visible emissions observation was performed.

(B) If video surveillance camera is used, the record must include all video surveillance images recorded, with time and date stamps.

(C) For each 2 hour period for which visible emissions are observed for more than 5 minutes in 2 consecutive hours, the record must include the date and time of the 2 hour period and an estimate of the cumulative number of minutes in the 2 hour period for which emissions were visible.

(iii) The 15-minute block average cumulative flows for flare vent gas and, if applicable, total steam, perimeter assist air, and premix assist air specified to be monitored under §63.670(i), along with the date and time interval for the 15-minute block. If multiple monitoring locations are used to determine cumulative vent gas flow, total steam, perimeter assist air, and premix assist air, retain records of the 15-minute block average flows for each monitoring location for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years. If pressure and temperature monitoring is used, retain records of the 15-minute block average temperature, pressure and molecular weight of the flare vent gas or assist gas stream for each measurement location used to determine the 15-minute block average cumulative flows for a minimum of 2 years, and retain the 15-minute block average cumulative flows that are used in subsequent calculations for a minimum of 5 years.

(iv) The flare vent gas compositions specified to be monitored under §63.670(j). Retain records of individual component concentrations from each compositional analyses for a minimum of 2 years. If NHVvg analyzer is used, retain records of the 15-minute block average values for a minimum of 5 years.

(v) Each 15-minute block average operating parameter calculated following the methods specified in §63.670(k) through (n), as applicable.

(vi) [Reserved]

(vii) All periods during which operating values are outside of the applicable operating limits specified in §63.670(d) through (f) when regulated material is being routed to the flare.

(viii) All periods during which the owner or operator does not perform flare monitoring according to the procedures in §63.670(g) through (j).

(ix) Records of periods when there is flow of vent gas to the flare, but when there is no flow of regulated material to the flare, including the start and stop time and dates of periods of no regulated material flow.

(x) Records when the flow of vent gas exceeds the smokeless capacity of the flare, including start and stop time and dates of the flaring event.

(xi) Records of the root cause analysis and corrective action analysis conducted as required in §63.670(o)(3), including an identification of the affected facility, the date and duration of the event, a statement noting whether the event resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under §63.670(o)(5)(i).

(xii) For any corrective action analysis for which implementation of corrective actions are required in §63.670(o)(5), a description of the corrective action(s) completed within the first 45 days following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(10) [Reserved]

(11) For each pressure relief device subject to the pressure release management work practice standards in §63.648(j)(3), the owner or operator shall keep the records specified in paragraphs (i)(11)(i) through (iii) of this section.

(i) Records of the prevention measures implemented as required in §63.648(j)(3)(ii), if applicable.

(ii) Records of the number of releases during each calendar year and the number of those releases for which the root cause was determined to be a force majeure event. Keep these records for the current calendar year and the past five calendar years.

(iii) For each release to the atmosphere, the owner or operator shall keep the records specified in paragraphs (i)(11)(iii)(A) through (D) of this section.

(A) The start and end time and date of each pressure release to the atmosphere.

(B) Records of any data, assumptions, and calculations used to estimate of the mass quantity of each organic HAP released during the event.

(C) Records of the root cause analysis and corrective action analysis conducted as required in §63.648(j)(3)(iii), including an identification of the affected facility, the date and duration of the event, a statement noting whether the event resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under §63.648(j)(7)(i).

(D) For any corrective action analysis for which implementation of corrective actions are required in §63.648(j)(7), a description of the corrective action(s) completed within the first 45 days following the discharge and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(12) For each maintenance vent opening subject to the requirements in §63.643(c), the owner or operator shall keep the applicable records specified in (i)(12)(i) through (v) of this section.

(i) The owner or operator shall maintain standard site procedures used to deinventory equipment for safety purposes (*e.g.,* hot work or vessel entry procedures) to document the procedures used to meet the requirements in §63.643(c).

The current copy of the procedures shall be retained and available on-site at all times. Previous versions of the standard site procedures, is applicable, shall be retained for five years.

(ii) If complying with the requirements of §63.643(c)(1)(i) and the lower explosive limit at the time of the vessel opening exceeds 10 percent, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and the lower explosive limit at the time of the vessel opening.

(iii) If complying with the requirements of §63.643(c)(1)(ii) and either the vessel pressure at the time of the vessel opening exceeds 5 psig or the lower explosive limit at the time of the active purging was initiated exceeds 10 percent, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, the pressure of the vessel or equipment at the time of discharge to the atmosphere and, if applicable, the lower explosive limit of the vapors in the equipment when active purging was initiated.

(iv) If complying with the requirements of §63.643(c)(1)(iii), identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and records used to estimate the total quantity of VOC in the equipment at the time the maintenance vent was opened to the atmosphere for each applicable maintenance vent opening.

(v) If complying with the requirements of §63.643(c)(1)(iv), identification of the maintenance vent, the process units or equipment associated with the maintenance vent, records documenting the lack of a pure hydrogen supply, the date of maintenance vent opening, and the lower explosive limit of the vapors in the equipment at the time of discharge to the atmosphere for each applicable maintenance vent opening.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29881, June 12, 1996; 63 FR 44141, Aug. 18, 1998. Redesignated and amended at 74 FR 55686, 55687, Oct. 28, 2009; 75 FR 37731, June 30, 2010; 78 FR 37148, June 20, 2013; 80 FR 75246, Dec. 1, 2015; 81 FR 45241, July 13, 2016]

§63.656 Implementation and enforcement.

(a) This subpart can be implemented and enforced by the U.S. EPA, or a delegated authority such as the applicable State, local, or Tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or Tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to a State, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or Tribal agency under subpart E of this part, the authorities contained in paragraph (c) of this section are retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or Tribal agency.

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (4) of this section.

(1) Approval of alternatives to the requirements in §§63.640, 63.642(g) through (l), 63.643, 63.646 through 63.652, 63.654, 63.657 through 63.660, and 63.670. Where these standards reference another subpart, the cited provisions will be delegated according to the delegation provisions of the referenced subpart. Where these standards reference another subpart and modify the requirements, the requirements shall be modified as described in this subpart. Delegation of the modified requirements will also occur according to the delegation provisions of the referenced subpart.

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f), as defined in §63.90, and as required in this subpart.

(3) Approval of major alternatives to monitoring under §63.8(f), as defined in §63.90, and as required in this subpart.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f), as defined in §63.90, and as required in this subpart.

[68 FR 37351, June 23, 2003. Redesignated and amended at 74 FR 55686, 55688, Oct. 28, 2009; 80 FR 75253, Dec. 1, 2015]

§63.657 Delayed coking unit decoking operation standards.

(a) Except as provided in paragraphs (e) and (f) of this section, each owner or operator of a delayed coking unit shall depressure each coke drum to a closed blowdown system until the coke drum vessel pressure or temperature measured at the top of the coke drum or in the overhead line of the coke drum as near as practical to the coke drum meets the applicable limits specified in paragraph (a)(1) or (2) of this section prior to venting to the atmosphere, draining or deheading the coke drum at the end of the cooling cycle.

(1) For delayed coking units at an existing affected source, meet either:

(i) An average vessel pressure of 2 psig determined on a rolling 60-event average; or

(ii) An average vessel temperature of 220 degrees Fahrenheit determined on a rolling 60-event average.

(2) For delayed coking units at a new affected source, meet either:

(i) A vessel pressure of 2.0 psig for each decoking event; or

(ii) A vessel temperature of 218 degrees Fahrenheit for each decoking event.

(b) Each owner or operator of a delayed coking unit complying with the pressure limits in paragraph (a)(1)(i) or (a)(2)(i) of this section shall install, operate, calibrate, and maintain a monitoring system, as specified in paragraphs (b)(1) through (5) of this section, to determine the coke drum vessel pressure.

(1) The pressure monitoring system must be in a representative location (at the top of the coke drum or in the overhead line as near as practical to the coke drum) that minimizes or eliminates pulsating pressure, vibration, and, to the extent practical, internal and external corrosion.

(2) The pressure monitoring system must be capable of measuring a pressure of 2.0 psig within ±0.5 psig.

(3) The pressure monitoring system must be verified annually or at the frequency recommended by the instrument manufacturer. The pressure monitoring system must be verified following any period of more than 24 hours throughout which the pressure exceeded the maximum rated pressure of the sensor, or the data recorder was off scale.

(4) All components of the pressure monitoring system must be visually inspected for integrity, oxidation and galvanic corrosion every 3 months, unless the system has a redundant pressure sensor.

(5) The output of the pressure monitoring system must be reviewed daily to ensure that the pressure readings fluctuate as expected between operating and cooling/decoking cycles to verify the pressure taps are not plugged. Plugged pressure taps must be unplugged or otherwise repaired prior to the next operating cycle.

(c) Each owner or operator of a delayed coking unit complying with the temperature limits in paragraph (a)(1)(ii) or (a)(2)(ii) of this section shall install, operate, calibrate, and maintain a continuous parameter monitoring system to measure the coke drum vessel temperature (at the top of the coke drum or in the overhead line as near as practical to the coke drum) according to the requirements specified in table 13 of this subpart.

(d) The owner or operator of a delayed coking unit shall determine the coke drum vessel pressure or temperature, as applicable, on a 5-minute rolling average basis while the coke drum is vented to the closed blowdown system and shall use the last complete 5-minute rolling average pressure or temperature just prior to initiating steps to isolate the coke drum prior to venting, draining or deheading to demonstrate compliance with the requirements in paragraph (a) of this section. Pressure or temperature readings after initiating steps to isolate the coke drum from the closed blowdown system just prior to atmospheric venting, draining, or deheading the coke drum shall not be used in determining the average coke drum vessel pressure or temperature for the purpose of compliance with the requirements in paragraph (a) of this section.

(e) The owner or operator of a delayed coking unit using the “water overflow” method of coke cooling must hardpipe the overflow water or otherwise prevent exposure of the overflow water to the atmosphere when transferring the overflow water to the overflow water storage tank whenever the coke drum vessel temperature exceeds 220 degrees Fahrenheit. The overflow water storage tank may be an open or fixed-roof tank provided that a submerged fill pipe (pipe outlet below existing liquid level in the tank) is used to transfer overflow water to the tank. The owner or operator of a delayed coking unit using the “water overflow” method of coke cooling shall determine the coke drum vessel temperature as specified in paragraphs (c) and (d) of this section regardless of the compliance method used to demonstrate compliance with the requirements in paragraph (a) of this section.

(f) The owner or operator of a delayed coking unit may partially drain a coke drum prior to achieving the applicable limits in paragraph (a) of this section in order to double-quench a coke drum that did not cool adequately using the normal cooling process steps provided that the owner or operator meets the conditions in paragraphs (f)(1) and (2) of this section.

(1) The owner or operator shall install, operate, calibrate, and maintain a continuous parameter monitoring system to measure the drain water temperature at the bottom of the coke drum or in the drain line as near as practical to the coke drum according to the requirements specified in table 13 of this subpart.

(2) The owner or operator must maintain the drain water temperature below 210 degrees Fahrenheit during the partial drain associated with the double-quench event.

[80 FR 75253, Dec. 1, 2015]

§63.658 Fenceline monitoring provisions.

(a) The owner or operator shall conduct sampling along the facility property boundary and analyze the samples in accordance with Methods 325A and 325B of appendix A of this part and paragraphs (b) through (k) of this section.

(b) The target analyte is benzene.

(c) The owner or operator shall determine passive monitor locations in accordance with Section 8.2 of Method 325A of appendix A of this part.

(1) As it pertains to this subpart, known sources of VOCs, as used in Section 8.2.1.3 in Method 325A of appendix A of this part for siting passive monitors, means a wastewater treatment unit, process unit, or any emission source requiring control according to the requirements of this subpart, including marine vessel loading operations. For marine vessel loading operations, one passive monitor should be sited on the shoreline adjacent to the dock.

(2) The owner or operator may collect one or more background samples if the owner or operator believes that an offsite upwind source or an onsite source excluded under §63.640(g) may influence the sampler measurements. If the owner or operator elects to collect one or more background samples, the owner of operator must develop and submit a site-specific monitoring plan for approval according to the requirements in paragraph (i) of this section. Upon approval of the site-specific monitoring plan, the background sampler(s) should be operated co-currently with the routine samplers.

(3) The owner or operator shall collect at least one co-located duplicate sample for every 10 field samples per sampling period and at least two field blanks per sampling period, as described in Section 9.3 in Method 325A of appendix A of this part. The co-located duplicates may be collected at any one of the perimeter sampling locations.

(4) The owner or operator shall follow the procedure in Section 9.6 of Method 325B of appendix A of this part to determine the detection limit of benzene for each sampler used to collect samples, background samples (if the owner or operator elects to do so), co-located samples and blanks.

(d) The owner or operator shall collect and record meteorological data according to the applicable requirements in paragraphs (d)(1) through (3) of this section.

(1) If a near-field source correction is used as provided in paragraph (i)(1) of this section or if an alternative test method is used that provides time-resolved measurements, the owner or operator shall:

(i) Use an on-site meteorological station in accordance with Section 8.3 of Method 325A of appendix A of this part.

(ii) Collect and record hourly average meteorological data, including temperature, barometric pressure, wind speed and wind direction and calculate daily unit vector wind direction and daily sigma theta.

(2) For cases other than those specified in paragraph (d)(1) of this section, the owner or operator shall collect and record sampling period average temperature and barometric pressure using either an on-site meteorological station in accordance with Section 8.3 of Method 325A of appendix A of this part or, alternatively, using data from a United States Weather Service (USWS) meteorological station provided the USWS meteorological station is within 40 kilometers (25 miles) of the refinery.

(3) If an on-site meteorological station is used, the owner or operator shall follow the calibration and standardization procedures for meteorological measurements in EPA-454/B-08-002 (incorporated by reference—see §63.14).

(e) The owner of operator shall use a sampling period and sampling frequency as specified in paragraphs (e)(1) through (3) of this section.

(1) *Sampling period.* A 14-day sampling period shall be used, unless a shorter sampling period is determined to be necessary under paragraph (g) or (i) of this section. A sampling period is defined as the period during which sampling tube is deployed at a specific sampling location with the diffusive sampling end cap in-place and does not include the time required to analyze the sample. For the purpose of this subpart, a 14-day sampling period may be no shorter than 13 calendar days and no longer than 15 calendar days, but the routine sampling period shall be 14 calendar days.

(2) *Base sampling frequency.* Except as provided in paragraph (e)(3) of this section, the frequency of sample collection shall be once each contiguous 14-day sampling period, such that the beginning of the next 14-day sampling period begins immediately upon the completion of the previous 14-day sampling period.

(3) *Alternative sampling frequency for burden reduction.* When an individual monitor consistently achieves results at or below 0.9 μg/m^3, the owner or operator may elect to use the applicable minimum sampling frequency specified in paragraphs (e)(3)(i) through (v) of this section for that monitoring site. When calculating Δc for the monitoring period when using this alternative for burden reduction, zero shall be substituted for the sample result for the monitoring site for any period where a sample is not taken.

(i) If every sample at a monitoring site is at or below 0.9 μg/m^3 for 2 years (52 consecutive samples), every other sampling period can be skipped for that monitoring site, *i.e.,* sampling will occur approximately once per month.

(ii) If every sample at a monitoring site that is monitored at the frequency specified in paragraph (e)(3)(i) of this section is at or below 0.9 μg/m^3 for 2 years (*i.e.,* 26 consecutive "monthly" samples), five 14-day sampling periods can be skipped for that monitoring site following each period of sampling, *i.e.,* sampling will occur approximately once per quarter.

(iii) If every sample at a monitoring site that is monitored at the frequency specified in paragraph (e)(3)(ii) of this section is at or below 0.9 μg/m^3 for 2 years (*i.e.,* 8 consecutive quarterly samples), twelve 14-day sampling periods can be skipped for that monitoring site following each period of sampling, *i.e.,* sampling will occur twice a year.

(iv) If every sample at a monitoring site that is monitored at the frequency specified in paragraph (e)(3)(iii) of this section is at or below 0.9 μg/m^3 for an 2 years (*i.e.,* 4 consecutive semi-annual samples), only one sample per year is required for that monitoring site. For yearly sampling, samples shall occur at least 10 months but no more than 14 months apart.

(v) If at any time a sample for a monitoring site that is monitored at the frequency specified in paragraphs (e)(3)(i) through (iv) of this section returns a result that is above 0.9 µg/m^3, the sampling site must return to the original sampling requirements of contiguous 14-day sampling periods with no skip periods for one quarter (six 14-day sampling periods). If every sample collected during this quarter is at or below 0.9 µg/m^3 , the owner or operator may revert back to the reduced monitoring schedule applicable for that monitoring site prior to the sample reading exceeding 0.9 µg/m^3 If any sample collected during this quarter is above 0.9 µg/m^3, that monitoring site must return to the original sampling requirements of contiguous 14-day sampling periods with no skip periods for a minimum of two years. The burden reduction requirements can be used again for that monitoring site once the requirements of paragraph (e)(3)(i) of this section are met again, *i.e.,* after 52 contiguous 14-day samples with no results above 0.9 µg/m^3 .

(f) Within 45 days of completion of each sampling period, the owner or operator shall determine whether the results are above or below the action level as follows:

(1) The owner or operator shall determine the facility impact on the benzene concentration (Δc) for each 14-day sampling period according to either paragraph (f)(1)(i) or (ii) of this section, as applicable.

(i) Except when near-field source correction is used as provided in paragraph (i) of this section, the owner or operator shall determine the highest and lowest sample results for benzene concentrations from the sample pool and calculate Δc as the difference in these concentrations. The owner or operator shall adhere to the following procedures when one or more samples for the sampling period are below the method detection limit for benzene:

(A) If the lowest detected value of benzene is below detection, the owner or operator shall use zero as the lowest sample result when calculating Δc.

(B) If all sample results are below the method detection limit, the owner or operator shall use the method detection limit as the highest sample result.

(ii) When near-field source correction is used as provided in paragraph (i) of this section, the owner or operator shall determine Δc using the calculation protocols outlined in the approved site-specific monitoring plan and in paragraph (i) of this section.

(2) The owner or operator shall calculate the annual average Δc based on the average of the 26 most recent 14-day sampling periods. The owner or operator shall update this annual average value after receiving the results of each subsequent 14-day sampling period.

(3) The action level for benzene is 9 micrograms per cubic meter (µg/m3) on an annual average basis. If the annual average Δc value for benzene is less than or equal to 9 µg/m^3, the concentration is below the action level. If the annual average Δc value for benzene is greater than 9 µg/m^3, the concentration is above the action level, and the owner or operator shall conduct a root cause analysis and corrective action in accordance with paragraph (g) of this section.

(g) Within 5 days of determining that the action level has been exceeded for any annual average Δc and no longer than 50 days after completion of the sampling period, the owner or operator shall initiate a root cause analysis to determine the cause of such exceedance and to determine appropriate corrective action, such as those described in paragraphs (g)(1) through (4) of this section. The root cause analysis and initial corrective action analysis shall be completed and initial corrective actions taken no later than 45 days after determining there is an exceedance. Root cause analysis and corrective action may include, but is not limited to:

(1) Leak inspection using Method 21 of part 60, appendix A-7 of this chapter and repairing any leaks found.

(2) Leak inspection using optical gas imaging and repairing any leaks found.

(3) Visual inspection to determine the cause of the high benzene emissions and implementing repairs to reduce the level of emissions.

(4) Employing progressively more frequent sampling, analysis and meteorology (*e.g.,* using shorter sampling periods for Methods 325A and 325B of appendix A of this part, or using active sampling techniques).

(h) If, upon completion of the corrective action analysis and corrective actions such as those described in paragraph (g) of this section, the Δc value for the next 14-day sampling period for which the sampling start time begins after the completion of the corrective actions is greater than 9 µg/m^3 or if all corrective action measures identified require more than 45 days to implement, the owner or operator shall develop a corrective action plan that describes the corrective action(s) completed to date, additional measures that the owner or operator proposes to employ to reduce fenceline concentrations below the action level, and a schedule for completion of these measures. The owner or operator shall submit the corrective action plan to the Administrator within 60 days after receiving the analytical results indicating that the Δc value for the 14-day sampling period following the completion of the initial corrective action is greater than 9 µg/m^3 or, if no initial corrective actions were identified, no later than 60 days following the completion of the corrective action analysis required in paragraph (g) of this section.

(i) An owner or operator may request approval from the Administrator for a site-specific monitoring plan to account for offsite upwind sources or onsite sources excluded under §63.640(g) according to the requirements in paragraphs (i)(1) through (4) of this section.

(1) The owner or operator shall prepare and submit a site-specific monitoring plan and receive approval of the site-specific monitoring plan prior to using the near-field source alternative calculation for determining Δc provided in paragraph (i)(2) of this section. The site-specific monitoring plan shall include, at a minimum, the elements specified in paragraphs (i)(1)(i) through (v) of this section. The procedures in Section 12 of Method 325A of appendix A of this part are not required, but may be used, if applicable, when determining near-field source contributions.

(i) Identification of the near-field source or sources. For onsite sources, documentation that the onsite source is excluded under §63.640(g) and identification of the specific provision in §63.640(g) that applies to the source.

(ii) Location of the additional monitoring stations that shall be used to determine the uniform background concentration and the near-field source concentration contribution.

(iii) Identification of the fenceline monitoring locations impacted by the near-field source. If more than one near-field source is present, identify the near-field source or sources that are expected to contribute to the concentration at that monitoring location.

(iv) A description of (including sample calculations illustrating) the planned data reduction and calculations to determine the near-field source concentration contribution for each monitoring location.

(v) If more frequent monitoring or a monitoring station other than a passive diffusive tube monitoring station is proposed, provide a detailed description of the measurement methods, measurement frequency, and recording frequency for determining the uniform background or near-field source concentration contribution.

(2) When an approved site-specific monitoring plan is used, the owner or operator shall determine Δc for comparison with the 9 µg/m^3 action level using the requirements specified in paragraphs (i)(2)(i) through (iii) of this section.

(i) For each monitoring location, calculate Δc_i using the following equation.

$$\Delta c_i = MFC_i - NFS_i - UB$$

Where:

Δc_i = The fenceline concentration, corrected for background, at measurement location i, micrograms per cubic meter (µg/m^3).

MFC_i = The measured fenceline concentration at measurement location i, µg/m^3.

NFS_i = The near-field source contributing concentration at measurement location i determined using the additional measurements and calculation procedures included in the site-specific monitoring plan, µg/m^3. For monitoring locations that are not included in the site-specific monitoring plan as impacted by a near-field source, use NFS_i = 0 µg/m^3.

UB = The uniform background concentration determined using the additional measurements included in the site-specific monitoring plan, µg/m^3. If no additional measurements are specified in the site-specific monitoring plan for determining the uniform background concentration, use UB = 0 µg/m^3.

(ii) When one or more samples for the sampling period are below the method detection limit for benzene, adhere to the following procedures:

(A) If the benzene concentration at the monitoring location used for the uniform background concentration is below the method detection limit, the owner or operator shall use zero for UB for that monitoring period.

(B) If the benzene concentration at the monitoring location(s) used to determine the near-field source contributing concentration is below the method detection limit, the owner or operator shall use zero for the monitoring location concentration when calculating NFS_i for that monitoring period.

(C) If a fenceline monitoring location sample result is below the method detection limit, the owner or operator shall use the method detection limit as the sample result.

(iii) Determine Δc for the monitoring period as the maximum value of Δc_i from all of the fenceline monitoring locations for that monitoring period.

(3) The site-specific monitoring plan shall be submitted and approved as described in paragraphs (i)(3)(i) through (iv) of this section.

(i) The site-specific monitoring plan must be submitted to the Administrator for approval.

(ii) The site-specific monitoring plan shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refineryrtr@epa.gov.*

(iii) The Administrator shall approve or disapprove the plan in 90 days. The plan shall be considered approved if the Administrator either approves the plan in writing, or fails to disapprove the plan in writing. The 90-day period shall begin when the Administrator receives the plan.

(iv) If the Administrator finds any deficiencies in the site-specific monitoring plan and disapproves the plan in writing, the owner or operator may revise and resubmit the site-specific monitoring plan following the requirements in paragraphs (i)(3)(i) and (ii) of this section. The 90-day period starts over with the resubmission of the revised monitoring plan.

(4) The approval by the Administrator of a site-specific monitoring plan will be based on the completeness, accuracy and reasonableness of the request for a site-specific monitoring plan. Factors that the Administrator will consider in reviewing the request for a site-specific monitoring plan include, but are not limited to, those described in paragraphs (i)(4)(i) through (v) of this section.

(i) The identification of the near-field source or sources. For onsite sources, the documentation provided that the onsite source is excluded under §63.640(g).

(ii) The monitoring location selected to determine the uniform background concentration or an indication that no uniform background concentration monitor will be used.

(iii) The location(s) selected for additional monitoring to determine the near-field source concentration contribution.

(iv) The identification of the fenceline monitoring locations impacted by the near-field source or sources.

(v) The appropriateness of the planned data reduction and calculations to determine the near-field source concentration contribution for each monitoring location.

(vi) If more frequent monitoring is proposed, the adequacy of the description of the measurement and recording frequency proposed and the adequacy of the rationale for using the alternative monitoring frequency.

(j) The owner or operator shall comply with the applicable recordkeeping and reporting requirements in §63.655(h) and (i).

(k) As outlined in §63.7(f), the owner or operator may submit a request for an alternative test method. At a minimum, the request must follow the requirements outlined in paragraphs (k)(1) through (7) of this section.

(1) The alternative method may be used in lieu of all or a partial number of passive samplers required in Method 325A of appendix A of this part.

(2) The alternative method must be validated according to Method 301 in appendix A of this part or contain performance based procedures and indicators to ensure self-validation.

(3) The method detection limit must nominally be at least an order of magnitude below the action level, *i.e.,* 0.9 $\mu g/m^3$ benzene. The alternate test method must describe the procedures used to provide field verification of the detection limit.

(4) The spatial coverage must be equal to or better than the spatial coverage provided in Method 325A of appendix A of this part.

(i) For path average concentration open-path instruments, the physical path length of the measurement shall be no more than a passive sample footprint (the spacing that would be provided by the sorbent traps when following Method 325A). For example, if Method 325A requires spacing monitors A and B 610 meters (2000 feet) apart, then the physical path length limit for the measurement at that portion of the fenceline shall be no more than 610 meters (2000 feet).

(ii) For range resolved open-path instrument or approach, the instrument or approach must be able to resolve an average concentration over each passive sampler footprint within the path length of the instrument.

(iii) The extra samplers required in Sections 8.2.1.3 of Method 325A may be omitted when they fall within the path length of an open-path instrument.

(5) At a minimum, non-integrating alternative test methods must provide a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(6) For alternative test methods capable of real time measurements (less than a 5 minute sampling and analysis cycle), the alternative test method may allow for elimination of data points corresponding to outside emission sources for purpose of calculation of the high point for the two week average. The alternative test method approach must have wind speed, direction and stability class of the same time resolution and within the footprint of the instrument.

(7) For purposes of averaging data points to determine the Δc for the 14-day average high sample result, all results measured under the method detection limit must use the method detection limit. For purposes of averaging data points for the 14-day average low sample result, all results measured under the method detection limit must use zero.

[80 FR 75254, Dec. 1, 2015, as amended at 81 FR 45241, July 13, 2016]

§63.660 Storage vessel provisions.

On and after the applicable compliance date for a Group 1 storage vessel located at a new or existing source as specified in §63.640(h), the owner or operator of a Group 1 storage vessel that is part of a new or existing source shall comply with the requirements in subpart WW or SS of this part according to the requirements in paragraphs (a) through (i) of this section.

(a) As used in this section, all terms not defined in §63.641 shall have the meaning given them in subpart A, WW, or SS of this part. The definitions of “Group 1 storage vessel” (paragraph (2)) and “Storage vessel” in §63.641 shall apply in lieu of the definition of “Storage vessel” in §63.1061.

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

(2) When an owner or operator and the Administrator 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, an appropriate method (based on the type of liquid stored) as published by EPA or a consensus-based standards organization shall be used. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, *http://www.astm.org*), the American National Standards Institute (ANSI, 1819 L Street NW., 6th Floor, Washington, DC 20036, (202) 293-8020, *http://www.ansi.org*), the American Gas Association (AGA, 400 North Capitol Street NW., 4th Floor, Washington, DC 20001, (202) 824-7000, *http://www.aga.org*), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, *http://www.asme.org*), the American Petroleum Institute (API, 1220 L Street NW., Washington, DC 20005-4070, (202) 682-8000, *http://www.api.org*), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356-0060, *http://www.naesb.org*).

(b) A floating roof storage vessel complying with the requirements of subpart WW of this part may comply with the control option specified in paragraph (b)(1) of this section and, if equipped with a ladder having at least one slotted leg, shall comply with one of the control options as described in paragraph (b)(2) of this section.

(1) In addition to the options presented in §§63.1063(a)(2)(viii)(A) and (B) and 63.1064, a floating roof storage vessel may comply with §63.1063(a)(2)(vii) using a flexible enclosure device and either a gasketed or welded cap on the top of the guidepole.

(2) Each opening through a floating roof for a ladder having at least one slotted leg shall be equipped with one of the configurations specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) A pole float in the slotted leg and pole wipers for both legs. The wiper or seal of the pole float must be at or above the height of the pole wiper.

(ii) A ladder sleeve and pole wipers for both legs of the ladder.

(iii) A flexible enclosure device and either a gasketed or welded cap on the top of the slotted leg.

(c) For the purposes of this subpart, references shall apply as specified in paragraphs (c)(1) through (6) of this section.

(1) All references to “the proposal date for a referencing subpart” and “the proposal date of the referencing subpart” in subpart WW of this part mean June 30, 2014.

(2) All references to “promulgation of the referencing subpart” and “the promulgation date of the referencing subpart” in subpart WW of this part mean February 1, 2016.

(3) All references to “promulgation date of standards for an affected source or affected facility under a referencing subpart” in subpart SS of this part mean February 1, 2016.

(4) All references to “the proposal date of the relevant standard established pursuant to CAA section 112(f)” in subpart SS of this part mean June 30, 2014.

(5) All references to “the proposal date of a relevant standard established pursuant to CAA section 112(d)” in subpart SS of this part mean July 14, 1994.

(6) All references to the “required control efficiency” in subpart SS of this part mean reduction of organic HAP emissions by 95 percent or to an outlet concentration of 20 ppmv.

(d) For an uncontrolled fixed roof storage vessel that commenced construction on or before June 30, 2014, and that meets the definition of “Group 1 storage vessel”, paragraph (2), in §63.641 but not the definition of “Group 1 storage vessel”, paragraph (1), in §63.641, the requirements of §63.982 and/or §63.1062 do not apply until the next time the storage vessel is completely emptied and degassed, or January 30, 2026, whichever occurs first.

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

(f) References in §63.1066(a) to initial startup notification requirements do not apply.

(g) References to the Notification of Compliance Status in §63.999(b) mean the Notification of Compliance Status required by §63.655(f).

(h) References to the Periodic Reports in §§63.1066(b) and 63.999(c) mean the Periodic Report required by §63.655(g).

(i) Owners or operators electing to comply with the requirements in subpart SS of this part for a Group 1 storage vessel must comply with the requirements in paragraphs (i)(1) through (3) of this section.

(1) If a flare is used as a control device, the flare shall meet the requirements of §63.670 instead of the flare requirements in §63.987.

(2) If a closed vent system contains a bypass line, the owner or operator shall comply with the provisions of either §63.983(a)(3)(i) or (ii) for each closed vent system that contains bypass lines that could divert a vent stream either directly to the atmosphere or to a control device that does not comply with the requirements in subpart SS of this part. Except as provided in paragraphs (i)(2)(i) and (ii) of this section, use of the bypass at any time to divert a Group 1 storage vessel to either directly to the atmosphere or to a control device that does not comply with the requirements in subpart SS of this part is an emissions standards violation. Equipment such as low leg drains and equipment subject to §63.648 are not subject to this paragraph (i)(2).

(i) If planned routine maintenance of the control device cannot be performed during periods that storage vessel emissions are vented to the control device or when the storage vessel is taken out of service for inspections or other planned maintenance reasons, the owner or operator may bypass the control device.

(ii) Periods for which storage vessel control device may be bypassed for planned routine maintenance of the control device shall not exceed 240 hours per calendar year.

(3) If storage vessel emissions are routed to a fuel gas system or process, the fuel gas system or process shall be operating at all times when regulated emissions are routed to it. The exception in §63.984(a)(1) does not apply.

[80 FR 75257, Dec. 1, 2015]

§63.670 Requirements for flare control devices.

On or before January 30, 2019, the owner or operator of a flare used as a control device for an emission point subject to this subpart shall meet the applicable requirements for flares as specified in paragraphs (a) through (q) of this section and the applicable requirements in §63.671. The owner or operator may elect to comply with the requirements of paragraph (r) of this section in lieu of the requirements in paragraphs (d) through (f) of this section, as applicable.

(a) [Reserved]

(b) *Pilot flame presence.* The owner or operator shall operate each flare with a pilot flame present at all times when regulated material is routed to the flare. Each 15-minute block during which there is at least one minute where no pilot flame is present when regulated material is routed to the flare is a deviation of the standard. Deviations in different 15-minute blocks from the same event are considered separate deviations. The owner or operator shall monitor for the presence of a pilot flame as specified in paragraph (g) of this section.

(c) *Visible emissions.* The owner or operator shall specify the smokeless design capacity of each flare and operate with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, when regulated material is routed to the flare and the flare vent gas flow rate is less than the smokeless design capacity of the flare. The owner or operator shall monitor for visible emissions from the flare as specified in paragraph (h) of this section.

(d) *Flare tip velocity.* For each flare, the owner or operator shall comply with either paragraph (d)(1) or (2) of this section, provided the appropriate monitoring systems are in-place, whenever regulated material is routed to the flare for at least 15-minutes and the flare vent gas flow rate is less than the smokeless design capacity of the flare.

(1) Except as provided in paragraph (d)(2) of this section, the actual flare tip velocity (V_{tip}) must be less than 60 feet per second. The owner or operator shall monitor V_{tip}using the procedures specified in paragraphs (i) and (k) of this section.

(2) V_{tip} must be less than 400 feet per second and also less than the maximum allowed flare tip velocity (V_{max}) as calculated according to the following equation. The owner or operator shall monitor Vtip using the procedures specified in paragraphs (i) and (k) of this section and monitor gas composition and determine NHV_{vg} using the procedures specified in paragraphs (j) and (l) of this section.

$$Log_{10}(V_{max}) = \frac{NHV_{vg} + 1{,}212}{850}$$

Where:

V_{max} = Maximum allowed flare tip velocity, ft/sec.

NHV_{vg} = Net heating value of flare vent gas, as determined by paragraph (l)(4) of this section, Btu/scf.

1,212 = Constant.

850 = Constant.

(e) *Combustion zone operating limits.* For each flare, the owner or operator shall operate the flare to maintain the net heating value of flare combustion zone gas (NHV_{cz}) at or above 270 British thermal units per standard cubic feet (Btu/scf) determined on a 15-minute block period basis when regulated material is routed to the flare for at least 15-minutes. The owner or operator shall monitor and calculate NHV_{cz} as specified in paragraph (m) of this section.

(f) *Dilution operating limits for flares with perimeter assist air.* For each flare actively receiving perimeter assist air, the owner or operator shall operate the flare to maintain the net heating value dilution parameter (NHVdil) at or above 22 British thermal units per square foot (Btu/ft^2) determined on a 15-minute block period basis when regulated material is being routed to the flare for at least 15-minutes. The owner or operator shall monitor and calculate NHV_{dil} as specified in paragraph (n) of this section.

(g) *Pilot flame monitoring.* The owner or operator shall continuously monitor the presence of the pilot flame(s) using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot flame(s) is present.

(h) *Visible emissions monitoring.* The owner or operator shall monitor visible emissions while regulated materials are vented to the flare. An initial visible emissions demonstration must be conducted using an observation period of 2 hours using Method 22 at 40 CFR part 60, appendix A-7. Subsequent visible emissions observations must be conducted using either the methods in paragraph (h)(1) of this section or, alternatively, the methods in paragraph (h)(2) of this section. The owner or operator must record and report any instances where visible emissions are observed for more than 5 minutes during any 2 consecutive hours as specified in §63.655(g)(11)(ii).

(1) At least once per day, conduct visible emissions observations using an observation period of 5 minutes using Method 22 at 40 CFR part 60, appendix A-7. If at any time the owner or operator sees visible emissions, even if the minimum required daily visible emission monitoring has already been performed, the owner or operator shall immediately begin an observation period of 5 minutes using Method 22 at 40 CFR part 60, appendix A-7. If visible emissions are observed for more than one continuous minute during any 5-minute observation period, the observation period using Method 22 at 40 CFR part 60, appendix A-7 must be extended to 2 hours or until 5-minutes of visible emissions are observed.

(2) Use a video surveillance camera to continuously record (at least one frame every 15 seconds with time and date stamps) images of the flare flame and a reasonable distance above the flare flame at an angle suitable for visual emissions observations. The owner or operator must provide real-time video surveillance camera output to the control room or other continuously manned location where the camera images may be viewed at any time.

(i) *Flare vent gas, steam assist and air assist flow rate monitoring.* The owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate in the flare header or headers that feed the flare as well as any supplemental natural gas used. Different flow monitoring methods may be used to measure different gaseous streams that make up the flare vent gas provided that the flow rates of all gas streams that contribute to the flare vent gas are determined. If assist air or assist steam is used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of assist air and/or assist steam used with the flare. If pre-mix assist air and perimeter assist are both used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of separately measuring, calculating, and recording the volumetric flow rate of premix assist air and perimeter assist air used with the flare. Continuously monitoring fan speed or power and using fan curves is an acceptable method for continuously monitoring assist air flow rates.

(1) The flow rate monitoring systems must be able to correct for the temperature and pressure of the system and output parameters in standard conditions (*i.e.,* a temperature of 20 °C (68  °F) and a pressure of 1 atmosphere).

(2) Mass flow monitors may be used for determining volumetric flow rate of flare vent gas provided the molecular weight of the flare vent gas is determined using compositional analysis as specified in paragraph (j) of this section so that the mass flow rate can be converted to volumetric flow at standard conditions using the following equation.

$$Q_{vol} = \frac{Q_{mass} \times 385.3}{MWt}$$

Where:

Q_{vol} = Volumetric flow rate, standard cubic feet per second.

Q_{mass} = Mass flow rate, pounds per second.

385.3 = Conversion factor, standard cubic feet per pound-mole.

MWt = Molecular weight of the gas at the flow monitoring location, pounds per pound-mole.

(3) Mass flow monitors may be used for determining volumetric flow rate of assist air or assist steam. Use equation in paragraph (i)(2) of this section to convert mass flow rates to volumetric flow rates. Use a molecular weight of 18 pounds per pound-mole for assist steam and use a molecular weight of 29 pounds per pound-mole for assist air.

(4) Continuous pressure/temperature monitoring system(s) and appropriate engineering calculations may be used in lieu of a continuous volumetric flow monitoring systems provided the molecular weight of the gas is known. For assist

steam, use a molecular weight of 18 pounds per pound-mole. For assist air, use a molecular weight of 29 pounds per pound-mole. For flare vent gas, molecular weight must be determined using compositional analysis as specified in paragraph (j) of this section.

(j) *Flare vent gas composition monitoring.* The owner or operator shall determine the concentration of individual components in the flare vent gas using either the methods provided in paragraph (j)(1) or (2) of this section, to assess compliance with the operating limits in paragraph (e) of this section and, if applicable, paragraphs (d) and (f) of this section. Alternatively, the owner or operator may elect to directly monitor the net heating value of the flare vent gas following the methods provided in paragraphs (j)(3) of this section and, if desired, may directly measure the hydrogen concentration in the flare vent gas following the methods provided in paragraphs (j)(4) of this section. The owner or operator may elect to use different monitoring methods for different gaseous streams that make up the flare vent gas using different methods provided the composition or net heating value of all gas streams that contribute to the flare vent gas are determined.

(1) Except as provided in paragraphs (j)(5) and (6) of this section, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring (*i.e.,* at least once every 15-minutes), calculating, and recording the individual component concentrations present in the flare vent gas.

(2) Except as provided in paragraphs (j)(5) and (6) of this section, the owner or operator shall install, operate, and maintain a grab sampling system capable of collecting an evacuated canister sample for subsequent compositional analysis at least once every eight hours while there is flow of regulated material to the flare. Subsequent compositional analysis of the samples must be performed according to Method 18 of 40 CFR part 60, appendix A-6, ASTM D6420-99 (Reapproved 2010), ASTM D1945-03 (Reapproved 2010), ASTM D1945-14 or ASTM UOP539-12 (all incorporated by reference—see §63.14).

(3) Except as provided in paragraphs (j)(5) and (6) of this section, the owner or operator shall install, operate, calibrate, and maintain a calorimeter capable of continuously measuring, calculating, and recording NHV_{vg} at standard conditions.

(4) If the owner or operator uses a continuous net heating value monitor according to paragraph (j)(3) of this section, the owner or operator may, at their discretion, install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the hydrogen concentration in the flare vent gas.

(5) Direct compositional or net heating value monitoring is not required for purchased (“pipeline quality”) natural gas streams. The net heating value of purchased natural gas streams may be determined using annual or more frequent grab sampling at any one representative location. Alternatively, the net heating value of any purchased natural gas stream can be assumed to be 920 Btu/scf.

(6) Direct compositional or net heating value monitoring is not required for gas streams that have been demonstrated to have consistent composition (or a fixed minimum net heating value) according to the methods in paragraphs (j)(6)(i) through (v) of this section.

(i) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(A) A description of the flare gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the flare gas stream/system and the affected flare(s) to be considered;

(B) A statement that there are no crossover or entry points to be introduced into the flare gas stream/system (this should be shown in the piping diagrams) prior to the point where the flow rate of the gas streams is measured;

(C) An explanation of the conditions that ensure that the flare gas net heating value is consistent and, if flare gas net heating value is expected to vary (*e.g.,* due to product loading of different material), the conditions expected to produce the flare gas with the lowest net heating value;

(D) The supporting test results from sampling the requested flare gas stream/system for the net heating value. Sampling data must include, at minimum, 2 weeks of daily measurement values (14 grab samples) for frequently operated flare gas streams/systems; for infrequently operated flare gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. If the flare gas stream composition can vary, samples must be taken during those conditions expected to result in lowest net heating value identified in paragraph (j)(6)(i)(C) of this section. The owner or operator shall determine net heating value for the gas stream using either gas composition analysis or net heating value monitor (with optional hydrogen concentration analyzer) according to the method provided in paragraph (l) of this section; and

(E) A description of how the 2 weeks (or seven samples for infrequently operated flare gas streams/systems) of monitoring results compares to the typical range of net heating values expected for the flare gas stream/system going to the affected flare (*e.g.,* “the samples are representative of typical operating conditions of the flare gas stream going to the loading rack flare” or “the samples are representative of conditions expected to yield the lowest net heating value of the flare gas stream going to the loading rack flare”).

(F) The net heating value to be used for all flows of the flare vent gas from the flare gas stream/system covered in the application. A single net heating value must be assigned to the flare vent gas either by selecting the lowest net heating value measured in the sampling program or by determining the 95th percent confidence interval on the mean value of all samples collected using the t-distribution statistic (which is 1.943 for 7 grab samples or 1.771 for 14 grab samples).

(ii) The effective date of the exemption is the date of submission of the information required in paragraph (j)(6)(i) of this section.

(iii) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (*e.g.,* the stream composition changes). If such a change occurs, the owner or operator shall follow the procedures in paragraph (j)(6)(iii)(A), (B), or (C) of this section.

(A) If the operation change results in a flare vent gas net heating value that is still within the range of net heating values included in the original application, the owner or operator shall determine the net heating value on a grab sample and record the results as proof that the net heating value assigned to the vent gas stream in the original application is still appropriate.

(B) If the operation change results in a flare vent gas net heating value that is lower than the net heating value assigned to the vent gas stream in the original application, the owner or operator may submit new information following the procedures of paragraph (j)(6)(i) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(C) If the operation change results in a flare vent gas net heating value has greater variability in the flare gas stream/system such the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin monitoring the composition or net heat content of the flare vent gas stream using the methods in this section (*i.e.,* grab samples every 8 hours until such time a continuous monitor, if elected, is installed).

(k) *Calculation methods for cumulative flow rates and determining compliance with Vtip operating limits*. The owner or operator shall determine V_{tip} on a 15-minute block average basis according to the following requirements.

(1) The owner or operator shall use design and engineering principles to determine the unobstructed cross sectional area of the flare tip. The unobstructed cross sectional area of the flare tip is the total tip area that vent gas can pass through. This area does not include any stability tabs, stability rings, and upper steam or air tubes because flare vent gas does not exit through them.

(2) The owner or operator shall determine the cumulative volumetric flow of flare vent gas for each 15-minute block average period using the data from the continuous flow monitoring system required in paragraph (i) of this section according to the following requirements, as applicable. If desired, the cumulative flow rate for a 15-minute block period only needs to include flow during those periods when regulated material is sent to the flare, but owners or operators may elect to calculate the cumulative flow rates across the entire 15-minute block period for any 15-minute block period where there is regulated material flow to the flare.

(i) Use set 15-minute time periods starting at 12 midnight to 12:15 a.m., 12:15 a.m. to 12:30 a.m. and so on concluding at 11:45 p.m. to midnight when calculating 15-minute block average flow volumes.

(ii) If continuous pressure/temperature monitoring system(s) and engineering calculations are used as allowed under paragraph (i)(4) of this section, the owner or operator shall, at a minimum, determine the 15-minute block average temperature and pressure from the monitoring system and use those values to perform the engineering calculations to determine the cumulative flow over the 15-minute block average period. Alternatively, the owner or operator may divide the 15-minute block average period into equal duration subperiods(*e.g.*, three 5-minute periods) and determine the average temperature and pressure for each subperiod, perform engineering calculations to determine the flow for each subperiod, then add the volumetric flows for the subperiods to determine the cumulative volumetric flow of vent gas for the 15-minute block average period.

(3) The 15-minute block average V_{tip} shall be calculated using the following equation.

$$V_{tip} = \frac{Q_{cum}}{Area \times 900}$$

Where:

V_{tip} = Flare tip velocity, feet per second.

Q_{cum} = Cumulative volumetric flow over 15-minute block average period, actual cubic feet.

Area = Unobstructed area of the flare tip, square feet.

900 = Conversion factor, seconds per 15-minute block average.

(4) If the owner or operator chooses to comply with paragraph (d)(2) of this section, the owner or operator shall also determine the net heating value of the flare vent gas following the requirements in paragraphs (j) and (l) of this section and calculate V_{max} using the equation in paragraph (d)(2) of this section in order to compare V_{tip} to V_{max} on a 15-minute block average basis.

(l) *Calculation methods for determining flare vent gas net heating value.* The owner or operator shall determine the net heating value of the flare vent gas (NHV_{vg}) based on the composition monitoring data on a 15-minute block average basis according to the following requirements.

(1) If compositional analysis data are collected as provided in paragraph (j)(1) or (2) of this section, the owner or operator shall determine NHV_{vg} of a specific sample by using the following equation.

$$NHV_{vg} = \sum_{i=1}^{n} x_i NHV_i$$

Where:

NHV_{vg} = Net heating value of flare vent gas, Btu/scf.

i = Individual component in flare vent gas.

n = Number of components in flare vent gas.

x_i = Concentration of component i in flare vent gas, volume fraction.

NHV_i = Net heating value of component i according to table 12 of this subpart, Btu/scf. If the component is not specified in table 12 of this subpart, the heats of combustion may be determined using any published values where the net enthalpy per mole of offgas is based on combustion at 25 °C and 1 atmosphere (or constant pressure) with offgas water in the gaseous state, but the standard temperature for determining the volume corresponding to one mole of vent gas is 20 °C.

(2) If direct net heating value monitoring data are collected as provided in paragraph (j)(3) of this section but a hydrogen concentration monitor is not used, the owner or operator shall use the direct output of the monitoring system(s) (in Btu/scf) to determine the NHV_{vg} for the sample.

(3) If direct net heating value monitoring data are collected as provided in paragraph (j)(3) of this section and hydrogen concentration monitoring data are collected as provided in paragraph (j)(4) of this section, the owner or operator shall use the following equation to determine NHV_{vg} for each sample measured via the net heating value monitoring system.

$$NHV_{vg} = NHV_{measured} + 938x_{H2}$$

Where:

NHV_{vg} = Net heating value of flare vent gas, Btu/scf.

$NHV_{measured}$ = Net heating value of flare vent gas stream as measured by the continuous net heating value monitoring system, Btu/scf.

x_{H2} = Concentration of hydrogen in flare vent gas at the time the sample was input into the net heating value monitoring system, volume fraction.

938 = Net correction for the measured heating value of hydrogen (1,212 − 274), Btu/scf.

(4) Use set 15-minute time periods starting at 12 midnight to 12:15 a.m., 12:15 a.m. to 12:30 a.m. and so on concluding at 11:45 p.m. to midnight when calculating 15-minute block averages.

(5) When a continuous monitoring system is used as provided in paragraph (j)(1) or (3) of this section and, if applicable, paragraph (j)(4) of this section, the owner or operator may elect to determine the 15-minute block average NHV_{vg} using either the calculation methods in paragraph (l)(5)(i) of this section or the calculation methods in paragraph (l)(5)(ii) of this section. The owner or operator may choose to comply using the calculation methods in paragraph (l)(5)(i) of this section for some flares at the petroleum refinery and comply using the calculation methods (l)(5)(ii) of this section for other flares. However, for each flare, the owner or operator must elect one calculation method that will apply at all times, and use that method for all continuously monitored flare vent streams associated with that flare. If the owner or operator intends to change the calculation method that applies to a flare, the owner or operator must notify the Administrator 30 days in advance of such a change.

(i) *Feed-forward calculation method.* When calculating NHV_{vg} for a specific 15-minute block:

(A) Use the results from the first sample collected during an event, (for periodic flare vent gas flow events) for the first 15-minute block associated with that event.

(B) If the results from the first sample collected during an event (for periodic flare vent gas flow events) are not available until after the second 15-minute block starts, use the results from the first sample collected during an event for the second 15-minute block associated with that event.

(C) For all other cases, use the results that are available from the most recent sample prior to the 15-minute block period for that 15-minute block period for all flare vent gas steams. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 a.m. and the analysis is completed at 12:38 a.m., the results are available at 12:38 a.m. and these results would be used to determine compliance during the 15-minute block period from 12:45 a.m. to 1:00 a.m.

(ii) *Direct calculation method.* When calculating NHV_{vg} for a specific 15-minute block:

(A) If the results from the first sample collected during an event (for periodic flare vent gas flow events) are not available until after the second 15-minute block starts, use the results from the first sample collected during an event for the first 15-minute block associated with that event.

(B) For all other cases, use the arithmetic average of all NHV_{vg} measurement data results that become available during a 15-minute block to calculate the 15-minute block average for that period. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 a.m. and the analysis is completed at 12:38 a.m., the results are available at 12:38 a.m. and these results would be used to determine compliance during the 15-minute block period from 12:30 a.m. to 12:45 a.m.

(6) When grab samples are used to determine flare vent gas composition:

(i) Use the analytical results from the first grab sample collected for an event for all 15-minute periods from the start of the event through the 15-minute block prior to the 15-minute block in which a subsequent grab sample is collected.

(ii) Use the results from subsequent grab sampling events for all 15 minute periods starting with the 15-minute block in which the sample was collected and ending with the 15-minute block prior to the 15-minute block in which the next grab sample is collected. For the purpose of this requirement, use the time the sample was collected rather than the time the analytical results become available.

(7) If the owner or operator monitors separate gas streams that combine to comprise the total flare vent gas flow, the 15-minute block average net heating value shall be determined separately for each measurement location according to the methods in paragraphs (l)(1) through (6) of this section and a flow-weighted average of the gas stream net heating values shall be used to determine the 15-minute block average net heating value of the cumulative flare vent gas.

(m) *Calculation methods for determining combustion zone net heating value.* The owner or operator shall determine the net heating value of the combustion zone gas (NHV_{cz}) as specified in paragraph (m)(1) or (2) of this section, as applicable.

(1) Except as specified in paragraph (m)(2) of this section, determine the 15-minute block average NHV_{cz} based on the 15-minute block average vent gas and assist gas flow rates using the following equation. For periods when there is no assist steam flow or premix assist air flow, $NHV_{cz} = NHV_{vg}$.

$$NHV_{cz} = \frac{Q_{vg} \times NHV_{vg}}{\left(Q_{vg} + Q_s + Q_{a,premix}\right)}$$

Where:

NHV_{cz} = Net heating value of combustion zone gas, Btu/scf.

NHV_{vg} = Net heating value of flare vent gas for the 15-minute block period, Btu/scf.

Q_{vg} = Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

(2) Owners or operators of flares that use the feed-forward calculation methodology in paragraph (l)(5)(i) of this section and that monitor gas composition or net heating value in a location representative of the cumulative vent gas stream and that directly monitor supplemental natural gas flow additions to the flare must determine the 15-minute block average NHV_{cz} using the following equation.

$$NHV_{cz} = \frac{\left(Q_{vg} - Q_{NG2} + Q_{NG1}\right) \times NHV_{vg} + \left(Q_{NG2} - Q_{NG1}\right) \times NHV_{NG}}{\left(Q_{vg} + Q_s + Q_{a,premix}\right)}$$

Where:

NHV_{cz} = Net heating value of combustion zone gas, Btu/scf.

NHV_{vg} = Net heating value of flare vent gas for the 15-minute block period, Btu/scf.

Q_{vg} = Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.

Q_{NG2} = Cumulative volumetric flow of supplemental natural gas to the flare during the 15-minute block period, scf.

Q_{NG1} = Cumulative volumetric flow of supplemental natural gas to the flare during the previous 15-minute block period, scf. For the first 15-minute block period of an event, use the volumetric flow value for the current 15-minute block period, *i.e.,* $Q_{NG1}=Q_{NG2}$.

NHV_{NG} = Net heating value of supplemental natural gas to the flare for the 15-minute block period determined according to the requirements in paragraph (j)(5) of this section, Btu/scf.

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

(n) *Calculation methods for determining the net heating value dilution parameter.* The owner or operator shall determine the net heating value dilution parameter (NHV_{dil}) as specified in paragraph (n)(1) or (2) of this section, as applicable.

(1) Except as specified in paragraph (n)(2) of this section, determine the 15-minute block average NHV_{dil} based on the 15-minute block average vent gas and perimeter assist air flow rates using the following equation only during periods when perimeter assist air is used. For 15-minute block periods when there is no cumulative volumetric flow of perimeter assist air, the 15-minute block average NHV_{dil} parameter does not need to be calculated.

$$NHV_{dil} = \frac{Q_{vg} \times Diam \times NHV_{vg}}{\left(Q_{vg} + Q_s + Q_{a,premix} + Q_{a,perimeter}\right)}$$

Where:

NHV_{dil} = Net heating value dilution parameter, Btu/ft^2.

NHV_{vg} = Net heating value of flare vent gas determined for the 15-minute block period, Btu/scf.

Q_{vg} = Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.

Diam = Effective diameter of the unobstructed area of the flare tip for flare vent gas flow, ft. Use the area as determined in paragraph (k)(1) of this section and determine the diameter as

$$Diam = 2 \times \sqrt{Area/\pi} \ .$$

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

$Q_{a,perimeter}$ = Cumulative volumetric flow of perimeter assist air during the 15-minute block period, scf.

(2) Owners or operators of flares that use the feed-forward calculation methodology in paragraph (l)(5)(i) of this section and that monitor gas composition or net heating value in a location representative of the cumulative vent gas stream and that directly monitor supplemental natural gas flow additions to the flare must determine the 15-minute block average NHV_{dil} using the following equation only during periods when perimeter assist air is used. For 15-

minute block periods when there is no cumulative volumetric flow of perimeter assist air, the 15-minute block average NHV_{dil} parameter does not need to be calculated.

$$NHV_{dil} = \frac{\left[\left(Q_{vg} - Q_{NG2} + Q_{NG1}\right) \times NHV_{vg} + \left(Q_{NG2} - Q_{NG1}\right) \times NHV_{NG}\right] \times Diam}{\left(Q_{vg} + Q_{s} + Q_{a,premix} + Q_{a,perimeter}\right)}$$

Where:

NHV_{dil} = Net heating value dilution parameter, Btu/ft^2.

NHV_{vg} = Net heating value of flare vent gas determined for the 15-minute block period, Btu/scf.

Q_{vg} = Cumulative volumetric flow of flare vent gas during the 15-minute block period, scf.

Q_{NG2} = Cumulative volumetric flow of supplemental natural gas to the flare during the 15-minute block period, scf.

Q_{NG1} = Cumulative volumetric flow of supplemental natural gas to the flare during the previous 15-minute block period, scf. For the first 15-minute block period of an event, use the volumetric flow value for the current 15-minute block period, *i.e.,* $Q_{NG1} = Q_{NG2}$.

NHV_{NG} = Net heating value of supplemental natural gas to the flare for the 15-minute block period determined according to the requirements in paragraph (j)(5) of this section, Btu/scf.

Diam = Effective diameter of the unobstructed area of the flare tip for flare vent gas flow, ft. Use the area as determined in paragraph (k)(1) of this section and determine the diameter as

$$Diam = 2 \times \sqrt{Area/\pi}\ .$$

Q_s = Cumulative volumetric flow of total steam during the 15-minute block period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of premix assist air during the 15-minute block period, scf.

$Q_{a,perimeter}$ = Cumulative volumetric flow of perimeter assist air during the 15-minute block period, scf.

(o) *Emergency flaring provisions.* The owner or operator of a flare that has the potential to operate above its smokeless capacity under any circumstance shall comply with the provisions in paragraphs (o)(1) through (8) of this section.

(1) Develop a flare management plan to minimize flaring during periods of startup, shutdown, or emergency releases. The flare management plan must include the information described in paragraphs (o)(1)(i) through (vii) of this section.

(i) A listing of all refinery process units, ancillary equipment, and fuel gas systems connected to the flare for each affected flare.

(ii) An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized or prevented during periods of startup, shutdown, or emergency releases. The flare minimization assessment must (at a minimum) consider the items in paragraphs (o)(1)(ii)(A) through (C) of this section. The assessment must provide clear rationale in terms of costs (capital and annual operating), natural gas offset credits (if applicable), technical feasibility, secondary environmental impacts and safety considerations for the selected minimization alternative(s) or a statement, with justifications, that flow reduction could not be achieved. Based upon the assessment, each owner or operator of an affected flare shall identify the minimization alternatives that it has implemented by the due date of the flare management plan and shall include a schedule for the prompt implementation of any selected measures that cannot reasonably be completed as of that date.

(A) Modification in startup and shutdown procedures to reduce the quantity of process gas discharge to the flare.

(B) Implementation of prevention measures listed for pressure relief devices in §63.648(j)(5) for each pressure relief device that can discharge to the flare.

(C) Installation of a flare gas recovery system or, for facilities that are fuel gas rich, a flare gas recovery system and a co-generation unit or combined heat and power unit.

(iii) A description of each affected flare containing the information in paragraphs (o)(1)(iii)(A) through (G) of this section.

(A) A general description of the flare, including whether it is a ground flare or elevated (including height), the type of assist system (*e.g.,* air, steam, pressure, non-assisted), whether the flare is used on a routine basis or if it is only used during periods of startup, shutdown or emergency release, and whether the flare is equipped with a flare gas recovery system.

(B) The smokeless capacity of the flare based on design conditions. Note: A single value must be provided for the smokeless capacity of the flare.

(C) The maximum vent gas flow rate (hydraulic load capacity).

(D) The maximum supplemental gas flow rate.

(E) For flares that receive assist steam, the minimum total steam rate and the maximum total steam rate.

(F) For flares that receive assist air, an indication of whether the fan/blower is single speed, multi-fixed speed (*e.g.*, high, medium, and low speeds), or variable speeds. For fans/blowers with fixed speeds, provide the estimated assist air flow rate at each fixed speed. For variable speeds, provide the design fan curve (*e.g.,* air flow rate as a function of power input).

(G) Simple process flow diagram showing the locations of the flare following components of the flare: Flare tip (date installed, manufacturer, nominal and effective tip diameter, tip drawing); knockout or surge drum(s) or pot(s) (including dimensions and design capacities); flare header(s) and subheader(s); assist system; and ignition system.

(iv) Description and simple process flow diagram showing all gas lines (including flare waste gas, purge or sweep gas (as applicable), supplemental gas) that are associated with the flare. For purge, sweep, supplemental gas, identify the type of gas used. Designate which lines are exempt from composition or net heating value monitoring and why (*e.g.*, natural gas, gas streams that have been demonstrated to have consistent composition, pilot gas). Designate which lines are monitored and identify on the process flow diagram the location and type of each monitor. Designate the pressure relief devices that are vented to the flare.

(v) For each flow rate, gas composition, net heating value or hydrogen concentration monitor identified in paragraph (o)(1)(iv) of this section, provide a detailed description of the manufacturer's specifications, including, but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance and quality assurance procedures.

(vi) For each pressure relief device vented to the flare identified in paragraph (o)(1)(iv) of this section, provide a detailed description of each pressure release device, including type of relief device (rupture disc, valve type) diameter of the relief device opening, set pressure of the relief device and listing of the prevention measures implemented. This information may be maintained in an electronic database on-site and does not need to be submitted as part of the flare management plan unless requested to do so by the Administrator.

(vii) Procedures to minimize or eliminate discharges to the flare during the planned startup and shutdown of the refinery process units and ancillary equipment that are connected to the affected flare, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(2) Each owner or operator required to develop and implement a written flare management plan as described in paragraph (o)(1) of this section must submit the plan to the Administrator as described in paragraphs (o)(2)(i) through (iii) of this section.

(i) The owner or operator must develop and implement the flare management plan no later than January 30, 2019 or at startup for a new flare that commenced construction on or after February 1, 2016.

(ii) The owner or operator must comply with the plan as submitted by the date specified in paragraph (o)(2)(i) of this section. The plan should be updated periodically to account for changes in the operation of the flare, such as new connections to the flare or the installation of a flare gas recovery system, but the plan need be re-submitted to the Administrator only if the owner or operator alters the design smokeless capacity of the flare. The owner or operator must comply with the updated plan as submitted.

(iii) All versions of the plan submitted to the Administrator shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refineryRTR@epa.gov*.

(3) The owner or operator of a flare subject to this subpart shall conduct a root cause analysis and a corrective action analysis for each flow event that contains regulated material and that meets either the criteria in paragraph (o)(3)(i) or (ii) of this section.

(i) The vent gas flow rate exceeds the smokeless capacity of the flare and visible emissions are present from the flare for more than 5 minutes during any 2 consecutive hours during the release event.

(ii) The vent gas flow rate exceeds the smokeless capacity of the flare and the 15-minute block average flare tip velocity exceeds the maximum flare tip velocity determined using the methods in paragraph (d)(2) of this section.

(4) A root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a flare flow event meeting the criteria in paragraph (o)(3)(i) or (ii) of this section. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (o)(4)(i) through (v) of this section.

(i) You may conduct a single root cause analysis and corrective action analysis for a single continuous flare flow event that meets both of the criteria in paragraphs (o)(3)(i) and (ii) of this section.

(ii) You may conduct a single root cause analysis and corrective action analysis for a single continuous flare flow event regardless of the number of 15-minute block periods in which the flare tip velocity was exceeded or the number of 2 hour periods that contain more the 5 minutes of visible emissions.

(iii) You may conduct a single root cause analysis and corrective action analysis for a single event that causes two or more flares that are operated in series (*i.e.,* cascaded flare systems) to have a flow event meeting the criteria in paragraph (o)(3)(i) or (ii) of this section.

(iv) You may conduct a single root cause analysis and corrective action analysis for a single event that causes two or more flares to have a flow event meeting the criteria in paragraph (o)(3)(i) or (ii) of this section, regardless of the configuration of the flares, if the root cause is reasonably expected to be a force majeure event, as defined in this subpart.

(v) Except as provided in paragraphs (o)(4)(iii) and (iv) of this section, if more than one flare has a flow event that meets the criteria in paragraph (o)(3)(i) or (ii) of this section during the same time period, an initial root cause analysis shall be conducted separately for each flare that has a flow event meeting the criteria in paragraph (o)(3)(i) or (ii) of this section. If the initial root cause analysis indicates that the flow events have the same root cause(s), the initially separate root cause analyses may be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

(5) Each owner or operator of a flare required to conduct a root cause analysis and corrective action analysis as specified in paragraphs (o)(3) and (4) of this section shall implement the corrective action(s) identified in the corrective action analysis in accordance with the applicable requirements in paragraphs (o)(5)(i) through (iii) of this section.

(i) All corrective action(s) must be implemented within 45 days of the event for which the root cause and corrective action analyses were required or as soon thereafter as practicable. If an owner or operator concludes that no corrective action should be implemented, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the event.

(ii) For corrective actions that cannot be fully implemented within 45 days following the event for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(iii) No later than 45 days following the event for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(6) The owner or operator shall determine the total number of events for which a root cause and corrective action analyses was required during the calendar year for each affected flare separately for events meeting the criteria in paragraph (o)(3)(i) of this section and those meeting the criteria in paragraph (o)(3)(ii) of this section. For the purpose of this requirement, a single root cause analysis conducted for an event that met both of the criteria in paragraphs (o)(3)(i) and (ii) of this section would be counted as an event under each of the separate criteria counts for that flare. Additionally, if a single root cause analysis was conducted for an event that caused multiple flares to meet the criteria in paragraph (o)(3)(i) or (ii) of this section, that event would count as an event for each of the flares for each criteria in paragraph (o)(3) of this section that was met during that event. The owner or operator shall also determine the total number of events for which a root cause and correct action analyses was required and the analyses concluded that the root cause was a force majeure event, as defined in this subpart.

(7) The following events would be a violation of this emergency flaring work practice standard.

(i) Any flow event for which a root cause analysis was required and the root cause was determined to be operator error or poor maintenance.

(ii) Two visible emissions exceedance events meeting the criteria in paragraph (o)(3)(i) of this section that were not caused by a force majeure event from a single flare in a 3 calendar year period for the same root cause for the same equipment.

(iii) Two flare tip velocity exceedance events meeting the criteria in paragraph (o)(3)(ii) of this section that were not caused by a force majeure event from a single flare in a 3 calendar year period for the same root cause for the same equipment.

(iv) Three visible emissions exceedance events meeting the criteria in paragraph (o)(3)(i) of this section that were not caused by a force majeure event from a single flare in a 3 calendar year period for any reason.

(v) Three flare tip velocity exceedance events meeting the criteria in paragraph (o)(3)(ii) of this section that were not caused by a force majeure event from a single flare in a 3 calendar year period for any reason.

(p) *Flare monitoring records.* The owner or operator shall keep the records specified in §63.655(i)(9).

(q) *Reporting.* The owner or operator shall comply with the reporting requirements specified in §63.655(g)(11).

(r) *Alternative means of emissions limitation.* An owner or operator may request approval from the Administrator for site-specific operating limits that shall apply specifically to a selected flare. Site-specific operating limits include alternative threshold values for the parameters specified in paragraphs (d) through (f) of this section as well as threshold values for operating parameters other than those specified in paragraphs (d) through (f) of this section. The owner or operator must demonstrate that the flare achieves 96.5 percent combustion efficiency (or 98 percent destruction efficiency) using the site-specific operating limits based on a performance evaluation as described in paragraph (r)(1) of this section. The request shall include information as described in paragraph (r)(2) of this section. The request shall be submitted and followed as described in paragraph (r)(3) of this section.

(1) The owner or operator shall prepare and submit a site-specific test plan and receive approval of the site-specific performance evaluation plan prior to conducting any flare performance evaluation test runs intended for use in

developing site-specific operating limits. The site-specific performance evaluation plan shall include, at a minimum, the elements specified in paragraphs (r)(1)(i) through (ix) of this section. Upon approval of the site-specific performance evaluation plan, the owner or operator shall conduct performance evaluation test runs for the flare following the procedures described in the site-specific performance evaluation plan.

(i) The design and dimensions of the flare, flare type (air-assisted only, steam-assisted only, air- and steam-assisted, pressure-assisted, or non-assisted), and description of gas being flared, including quantity of gas flared, frequency of flaring events (if periodic), expected net heating value of flare vent gas, minimum total steam assist rate.

(ii) The operating conditions (vent gas compositions, vent gas flow rates and assist flow rates, if applicable) likely to be encountered by the flare during normal operations and the operating conditions for the test period.

(iii) A description of (including sample calculations illustrating) the planned data reduction and calculations to determine the flare combustion or destruction efficiency.

(iv) Site-specific operating parameters to be monitored continuously during the flare performance evaluation. These parameters may include but are not limited to vent gas flow rate, steam and/or air assist flow rates, and flare vent gas composition. If new operating parameters are proposed for use other than those specified in paragraphs (d) through (f) of this section, an explanation of the relevance of the proposed operating parameter(s) as an indicator of flare combustion performance and why the alternative operating parameter(s) can adequately ensure that the flare achieves the required combustion efficiency.

(v) A detailed description of the measurement methods, monitored pollutant(s), measurement locations, measurement frequency, and recording frequency proposed for both emission measurements and flare operating parameters.

(vi) A description of (including sample calculations illustrating) the planned data reduction and calculations to determine the flare operating parameters.

(vii) The minimum number and length of test runs and range of operating values to be evaluated during the performance evaluation. A sufficient number of test runs shall be conducted to identify the point at which the combustion/destruction efficiency of the flare deteriorates.

(viii) [Reserved]

(ix) Test schedule.

(2) The request for flare-specific operating limits shall include sufficient and appropriate data, as determined by the Administrator, to allow the Administrator to confirm that the selected site-specific operating limit(s) adequately ensures that the flare destruction efficiency is 98 percent or greater or that the flare combustion efficiency is 96.5 percent or greater at all times. At a minimum, the request shall contain the information described in paragraphs (r)(2)(i) through (iv) of this section.

(i) The design and dimensions of the flare, flare type (air-assisted only, steam-assisted only, air- and steam-assisted, pressure-assisted, or non-assisted), and description of gas being flared, including quantity of gas flared, frequency of flaring events (if periodic), expected net heating value of flare vent gas, minimum total steam assist rate.

(ii) Results of each performance evaluation test run conducted, including, at a minimum:

(A) The measured combustion/destruction efficiency.

(B) The measured or calculated operating parameters for each test run. If operating parameters are calculated, the raw data from which the parameters are calculated must be included in the test report.

(C) Measurement location descriptions for both emission measurements and flare operating parameters.

(D) Description of sampling and analysis procedures (including number and length of test runs) and any modifications to standard procedures. If there were deviations from the approved test plan, a detailed description of the deviations and rationale why the test results or calculation procedures used are appropriate.

(E) Operating conditions (*e.g.*, vent gas composition, assist rates, etc.) that occurred during the test.

(F) Quality assurance procedures.

(G) Records of calibrations.

(H) Raw data sheets for field sampling.

(I) Raw data sheets for field and laboratory analyses.

(J) Documentation of calculations.

(iii) The selected flare-specific operating limit values based on the performance evaluation test results, including the averaging time for the operating limit(s), and rationale why the selected values and averaging times are sufficiently stringent to ensure proper flare performance. If new operating parameters or averaging times are proposed for use other than those specified in paragraphs (d) through (f) of this section, an explanation of why the alternative operating parameter(s) or averaging time(s) adequately ensures the flare achieves the required combustion efficiency.

(iv) The means by which the owner or operator will document on-going, continuous compliance with the selected flare-specific operating limit(s), including the specific measurement location and frequencies, calculation procedures, and records to be maintained.

(3) The request shall be submitted as described in paragraphs (r)(3)(i) through (iv) of this section.

(i) The owner or operator may request approval from the Administrator at any time upon completion of a performance evaluation conducted following the methods in an approved site-specific performance evaluation plan for an operating limit(s) that shall apply specifically to that flare.

(ii) The request must be submitted to the Administrator for approval. The owner or operator must continue to comply with the applicable standards for flares in this subpart until the requirements in §63.6(g)(1) are met and a notice is published in the FEDERAL REGISTER allowing use of such an alternative means of emission limitation.

(iii) The request shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143-01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refineryrtr@epa.gov.*

(iv) If the Administrator finds any deficiencies in the request, the request must be revised to address the deficiencies and be re-submitted for approval within 45 days of receipt of the notice of deficiencies. The owner or operator must comply with the revised request as submitted until it is approved.

(4) The approval process for a request for a flare-specific operating limit(s) is described in paragraphs (r)(4)(i) through (iii) of this section.

(i) Approval by the Administrator of a flare-specific operating limit(s) request will be based on the completeness, accuracy and reasonableness of the request. Factors that the EPA will consider in reviewing the request for approval include, but are not limited to, those described in paragraphs (r)(4)(i)(A) through (C) of this section.

(A) The description of the flare design and operating characteristics.

(B) If a new operating parameter(s) other than those specified in paragraphs (d) through (f) of this section is proposed, the explanation of how the proposed operating parameter(s) serves a good indicator(s) of flare combustion performance.

(C) The results of the flare performance evaluation test runs and the establishment of operating limits that ensures that the flare destruction efficiency is 98 percent or greater or that the flare combustion efficiency is 96.5 percent or greater at all times.

(D) The completeness of the flare performance evaluation test report.

(ii) If the request is approved by the Administrator, a flare-specific operating limit(s) will be established at the level(s) demonstrated in the approved request.

(iii) If the Administrator finds any deficiencies in the request, the request must be revised to address the deficiencies and be re-submitted for approval.

[80 FR 75258, Dec. 1, 2015, as amended at 81 FR 45241, July 13, 2016]

§63.671 Requirements for flare monitoring systems.

(a) *Operation of CPMS*. For each CPMS installed to comply with applicable provisions in §63.670, the owner or operator shall install, operate, calibrate, and maintain the CPMS as specified in paragraphs (a)(1) through (8) of this section.

(1) Except for CPMS installed for pilot flame monitoring, all monitoring equipment must meet the applicable minimum accuracy, calibration and quality control requirements specified in table 13 of this subpart.

(2) The owner or operator shall ensure the readout (that portion of the CPMS that provides a visual display or record) or other indication of the monitored operating parameter from any CPMS required for compliance is readily accessible onsite for operational control or inspection by the operator of the source.

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

(4) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall operate all CPMS and collect data continuously at all times when regulated emissions are routed to the flare.

(5) The owner or operator shall operate, maintain, and calibrate each CPMS according to the CPMS monitoring plan specified in paragraph (b) of this section.

(6) For each CPMS except for CPMS installed for pilot flame monitoring, the owner or operator shall comply with the out-of-control procedures described in paragraph (c) of this section.

(7) The owner or operator shall reduce data from a CPMS as specified in paragraph (d) of this section.

(8) The CPMS must be capable of measuring the appropriate parameter over the range of values expected for that measurement location. The data recording system associated with each CPMS must have a resolution that is equal to or better than the required system accuracy.

(b) *CPMS monitoring plan.* The owner or operator shall develop and implement a CPMS quality control program documented in a CPMS monitoring plan that covers each flare subject to the provisions in §63.670 and each CPMS installed to comply with applicable provisions in §63.670. The owner or operator shall have the CPMS monitoring plan readily available on-site at all times and shall submit a copy of the CPMS monitoring plan to the Administrator upon request by the Administrator. The CPMS monitoring plan must contain the information listed in paragraphs (b)(1) through (5) of this section.

(1) Identification of the specific flare being monitored and the flare type (air-assisted only, steam-assisted only, air- and steam-assisted, pressure-assisted, or non-assisted).

(2) Identification of the parameter to be monitored by the CPMS and the expected parameter range, including worst case and normal operation.

(3) Description of the monitoring equipment, including the information specified in paragraphs (b)(3)(i) through (vii) of this section.

(i) Manufacturer and model number for all monitoring equipment components installed to comply with applicable provisions in §63.670.

(ii) Performance specifications, as provided by the manufacturer, and any differences expected for this installation and operation.

(iii) The location of the CPMS sampling probe or other interface and a justification of how the location meets the requirements of paragraph (a)(1) of this section.

(iv) Placement of the CPMS readout, or other indication of parameter values, indicating how the location meets the requirements of paragraph (a)(2) of this section.

(v) Span of the CPMS. The span of the CPMS sensor and analyzer must encompass the full range of all expected values.

(vi) How data outside of the span of the CPMS will be handled and the corrective action that will be taken to reduce and eliminate such occurrences in the future.

(vii) Identification of the parameter detected by the parametric signal analyzer and the algorithm used to convert these values into the operating parameter monitored to demonstrate compliance, if the parameter detected is different from the operating parameter monitored.

(4) Description of the data collection and reduction systems, including the information specified in paragraphs (b)(4)(i) through (iii) of this section.

(i) A copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard and to calculate the applicable averages.

(ii) Identification of whether the algorithm excludes data collected during CPMS breakdowns, out-of-control periods, repairs, maintenance periods, instrument adjustments or checks to maintain precision and accuracy, calibration checks, and zero (low-level), mid-level (if applicable) and high-level adjustments.

(iii) If the data acquisition algorithm does not exclude data collected during CPMS breakdowns, out-of-control periods, repairs, maintenance periods, instrument adjustments or checks to maintain precision and accuracy, calibration checks, and zero (low-level), mid-level (if applicable) and high-level adjustments, a description of the procedure for excluding this data when the averages calculated as specified in paragraph (e) of this section are determined.

(5) Routine quality control and assurance procedures, including descriptions of the procedures listed in paragraphs (b)(5)(i) through (vi) of this section and a schedule for conducting these procedures. The routine procedures must provide an assessment of CPMS performance.

(i) Initial and subsequent calibration of the CPMS and acceptance criteria.

(ii) Determination and adjustment of the calibration drift of the CPMS.

(iii) Daily checks for indications that the system is responding. If the CPMS system includes an internal system check, the owner or operator may use the results to verify the system is responding, as long as the system provides an alarm to the owner or operator or the owner or operator checks the internal system results daily for proper operation and the results are recorded.

(iv) Preventive maintenance of the CPMS, including spare parts inventory.

(v) Data recording, calculations and reporting.

(vi) Program of corrective action for a CPMS that is not operating properly.

(c) *Out-of-control periods*. For each CPMS installed to comply with applicable provisions in §63.670 except for CPMS installed for pilot flame monitoring, the owner or operator shall comply with the out-of-control procedures described in paragraphs (c)(1) and (2) of this section.

(1) A CPMS is out-of-control if the zero (low-level), mid-level (if applicable) or high-level calibration drift exceeds two times the accuracy requirement of table 13 of this subpart.

(2) When the CPMS is out of control, the owner or operator shall take the necessary corrective action and repeat all necessary tests that indicate the system is out of control. The owner or operator shall take corrective action and conduct retesting until the performance requirements are below the applicable limits. The beginning of the out-of-control period is the hour a performance check (*e.g.*, calibration drift) that indicates an exceedance of the performance requirements established in this section is conducted. The end of the out-of-control period is the hour following the completion of corrective action and successful demonstration that the system is within the allowable limits. The owner or operator shall not use data recorded during periods the CPMS is out of control in data averages and calculations, used to report emissions or operating levels, as specified in paragraph (d)(3) of this section.

(d) *CPMS data reduction*. The owner or operator shall reduce data from a CPMS installed to comply with applicable provisions in §63.670 as specified in paragraphs (d)(1) through (3) of this section.

(1) The owner or operator may round the data to the same number of significant digits used in that operating limit.

(2) Periods of non-operation of the process unit (or portion thereof) resulting in cessation of the emissions to which the monitoring applies must not be included in the 15-minute block averages.

(3) Periods when the CPMS is out of control must not be included in the 15-minute block averages.

(e) *Additional requirements for gas chromatographs.* For monitors used to determine compositional analysis for net heating value per §63.670(j)(1), the gas chromatograph must also meet the requirements of paragraphs (e)(1) through (3) of this section.

(1) The quality assurance requirements are in table 13 of this subpart.

(2) The calibration gases must meet one of the following options:

(i) The owner or operator must use a calibration gas or multiple gases that include all of compounds listed in paragraphs (e)(2)(i)(A) through (K) of this section that may be reasonably expected to exist in the flare gas stream and optionally include any of the compounds listed in paragraphs (e)(2)(i)(L) through (O) of this section. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, the owner or operator must calibrate the instrument on all of the gases.

(A) Hydrogen.

(B) Methane.

(C) Ethane.

(D) Ethylene.

(E) Propane.

(F) Propylene.

(G) n-Butane.

(H) iso-Butane.

(I) Butene (general). It is not necessary to separately speciate butene isomers, but the net heating value of trans-butene must be used for co-eluting butene isomers.

(J) 1,3-Butadiene. It is not necessary to separately speciate butadiene isomers, but you must use the response factor and net heating value of 1,3-butadiene for co-eluting butadiene isomers.

(K) n-Pentane. Use the response factor for n-pentane to quantify all C5+ hydrocarbons.

(L) Acetylene (optional).

(M) Carbon monoxide (optional).

(N) Propadiene (optional).

(O) Hydrogen sulfide (optional).

(ii) The owner or operator must use a surrogate calibration gas consisting of hydrogen and C1 through C5 normal hydrocarbons. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, the owner or operator must calibrate the instrument on all of the gases.

(3) If the owner or operator chooses to use a surrogate calibration gas under paragraph (e)(2)(ii) of this section, the owner or operator must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) Use the response factor for the nearest normal hydrocarbon (*i.e.,* n-alkane) in the calibration mixture to quantify unknown components detected in the analysis.

(ii) Use the response factor for n-pentane to quantify unknown components detected in the analysis that elute after n-pentane.

[80 FR 75266, Dec. 1, 2015]

§§63.672-63.679 [Reserved]

Appendix to Subpart CC of Part 63—Tables

Table 1—Hazardous Air Pollutants

Chemical name	**CAS No.**[a]
Benzene	71432
Biphenyl	92524
Butadiene (1,3)	106990

Chemical name	**CAS No.**[a]
Carbon disulfide	75150
Carbonyl sulfide	463581
Cresol (mixed isomers[b])	1319773
Cresol (m-)	108394
Cresol (o-)	95487
Cresol (p-)	106445
Cumene	98828
Dibromoethane (1,2) (ethylene dibromide)	106934
Dichloroethane (1,2)	107062
Diethanolamine	111422
Ethylbenzene	100414
Ethylene glycol	107211
Hexane	110543
Methanol	67561
Methyl isobutyl ketone (hexone)	108101
Methyl tert butyl ether	1634044
Naphthalene	91203
Phenol	108952
Toluene	108883
Trimethylpentane (2,2,4)	540841
Xylene (mixed isomers[b])	1330207
xylene (m-)	108383
xylene (o-)	95476
xylene (p-)	106423

aCAS number = Chemical Abstract Service registry number assigned to specific compounds, isomers, or mixtures of compounds.

bIsomer means all structural arrangements for the same number of atoms of each element and does not mean salts, esters, or derivatives.

Table 2—Leak Definitions for Pumps and Valves

Standard[a]	**Phase**	**Leak definition (parts per million)**
§63.163 (pumps)	I	10,000
	II	5,000
	III	2,000
§63.168 (valves)	I	10,000

Standard[a]	Phase	Leak definition (parts per million)
	II	1,000
	III	1,000

[a] Subpart H of this part.

Table 3—Equipment Leak Recordkeeping and Reporting Requirements for Sources Complying With §63.648 of Subpart CC by Compliance With Subpart H of this Parta

Reference (section of subpart H of this part)	Description	Comment
63.181(a)	Recordkeeping system requirements	Except for §§63.181(b)(2)(iii) and 63.181(b)(9).
63.181(b)	Records required for process unit equipment	Except for §§63.181(b)(2)(iii) and 63.181(b)(9).
63.181(c)	Visual inspection documentation	Except for §§63.181(b)(2)(iii) and 63.181(b)(9).
63.181(d)	Leak detection record requirements	Except for §63.181(d)(8).
63.181(e)	Compliance requirements for pressure tests for batch product process equipment trains	This subsection does not apply to subpart CC.
63.181(f)	Compressor compliance test records.	
63.181(g)	Closed-vent systems and control device record requirements.	
63.181(h)	Process unit quality improvement program records.	
63.181(i)	Heavy liquid service determination record.	
63.181(j)	Equipment identification record.	
63.181(k)	Enclosed-vented process unit emission limitation record requirements.	
63.182(a)	Reports.	
63.182(b)	Initial notification report requirements.	Not required.
63.182(c)	Notification of compliance status report	Except in §63.182(c); change “within 90 days of the compliance dates” to “within 150 days of the compliance dates”; except in §§63.182 (c)(2) and (c)(4).
63.182(d)	Periodic report	Except for §§63.182 (d)(2)(vii), (d)(2)(viii), and (d)(3).

[a] This table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

Table 4—Gasoline Distribution Emission Point Recordkeeping and Reporting Requirementsa

Reference (section of subpart R)	Description	Comment
63.428(b) or (k)	Records of test results for each gasoline cargo tank loaded at the facility	
63.428(c)	Continuous monitoring data recordkeeping requirements	
63.428(g)(1)	Semiannual report loading rack information	Required to be submitted with the Periodic Report required under 40 CFR part 63, subpart CC.
63.428(h)(1) through (h)(3)	Excess emissions report loading rack information	Required to be submitted with the Periodic Report required under 40 CFR part 63, subpart CC.

[a]This table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

Table 5—Marine Vessel Loading Operations Recordkeeping and Reporting Requirementsa

Reference (section of subpart Y)	Description	Comment
63.562(e)(2)	Operation and maintenance plan for control equipment and monitoring equipment	
63.565(a)	Performance test/site test plan	The information required under this paragraph is to be submitted with the Notification of Compliance Status report required under 40 CFR part 63, subpart CC.
63.565(b)	Performance test data requirements	
63.567(a)	General Provisions (subpart A) applicability	
63.567(c)	Request for extension of compliance	
63.567(d)	Flare recordkeeping requirements	
63.567(e)	Summary report and excess emissions and monitoring system performance report requirements	The information required under this paragraph is to be submitted with the Periodic Report required under 40 CFR part 63, subpart CC.
63.567(f)	Vapor collection system engineering report	
63.567(g)	Vent system valve bypass recordkeeping requirements	
63.567(h)	Marine vessel vapor-tightness documentation	
63.567(i)	Documentation file maintenance	
63.567(j)	Emission estimation reporting and recordkeeping procedures	

[a]This table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

Table 6—General Provisions Applicability to Subpart CCa

Reference	Applies to subpart CC	Comment
63.1(a)(1)	Yes	
63.1(a)(2)	Yes	
63.1(a)(3)	Yes	
63.1(a)(4)	Yes	
63.1(a)(5)	No	Reserved.
63.1(a)(6)	Yes	Except the correct mail drop (MD) number is C404-04.
63.1(a)(7)-63.1(a)(9)	No	Reserved.
63.1(a)(10)	Yes	
63.1(a)(11)	Yes	
63.1(a)(12)	Yes	
63.1(b)(1)	Yes	
63.1(b)(2)	No	Reserved.
63.1(b)(3)	No	
63.1(c)(1)	Yes	
63.1(c)(2)	No	Area sources are not subject to subpart CC.
63.1(c)(3)-63.1(c)(4)	No	Reserved.
63.1(c)(5)	Yes	Except that sources are not required to submit notifications overridden by this table.
63.1(d)	No	Reserved.
63.1(e)	No	No CAA section 112(j) standard applies to the affected sources under subpart CC.
63.2	Yes	§63.641 of subpart CC specifies that if the same term is defined in subparts A and CC, it shall have the meaning given in subpart CC.
63.3	Yes	
63.4(a)(1)-63.4(a)(2)	Yes	
63.4(a)(3)-63.4(a)(5)	No	Reserved.
63.4(b)	Yes	
63.4(c)	Yes	
63.5(a)	Yes	
63.5(b)(1)	Yes	

Reference	Applies to subpart CC	Comment
63.5(b)(2)	No	Reserved.
63.5(b)(3)	Yes	
63.5(b)(4)	Yes	Except the cross-reference to §63.9(b) is changed to §63.9(b)(4) and (5). Subpart CC overrides §63.9 (b)(2).
63.5(b)(5)	No	Reserved.
63.5(b)(6)	Yes	
63.5(c)	No	Reserved.
63.5(d)(1)(i)	Yes	Except that the application shall be submitted as soon as practicable before startup, but no later than 90 days after the promulgation date of subpart CC if the construction or reconstruction had commenced and initial startup had not occurred before the promulgation of subpart CC.
63.5(d)(1)(ii)	Yes	Except that for affected sources subject to this subpart, emission estimates specified in §63.5(d)(1)(ii)(H) are not required, and §63.5(d)(1)(ii)(G) and (I) are Reserved and do not apply.
63.5(d)(1)(iii)	No	Subpart CC §63.655(f) specifies Notification of Compliance Status report requirements.
63.5(d)(2)	Yes	
63.5(d)(3)	Yes	
63.5(d)(4)	Yes	
63.5(e)	Yes	
63.5(f)	Yes	Except that the cross-reference in §63.5(f)(2) to §63.9(b)(2) does not apply.
63.6(a)	Yes	
63.6(b)(1)-63.6(b)(5)	No	Subpart CC specifies compliance dates and notifications for sources subject to subpart CC.
63.6(b)(6)	No	Reserved.
63.6(b)(7)	Yes	
63.6(c)(1)-63.6(c)(2)	No	§63.640 of subpart CC specifies the compliance date.
63.6(c)(3)-63.6(c)(4)	No	Reserved.
63.6(c)(5)	Yes	
63.6(d)	No	Reserved.
63.6(e)(1)(i) and (ii)	No	See §63.642(n) for general duty requirement.
63.6(e)(1)(iii)	Yes.	
63.6(e)(2)	No	Reserved.
63.6(e)(3)(i)	No.	
63.6(e)(3)(ii)	No	Reserved.

Reference	**Applies to subpart CC**	**Comment**
63.6(e)(3)(iii)- 63.6(e)(3)(ix)	No.	
63.6(f)(1)	No.	
63.6(f)(2)	Yes	Except the phrase “as specified in §63.7(c)” in §63.6(f)(2)(iii)(D) does not apply because this subpart does not require a site-specific test plan.
63.6(f)(3)	Yes	Except the cross-references to §63.6(f)(1) and (e)(1)(i) are changed to §63.642(n).
63.6(g)	Yes	
63.6(h)(1)	No.	
63.6(h)(2)	Yes	Except §63.6(h)(2)(ii), which is reserved.
63.6(h)(3)	No	Reserved.
63.6(h)(4)	No	Notification of visible emission test not required in subpart CC.
63.6(h)(5)	No	Visible emission requirements and timing is specified in §63.645(i) of subpart CC.
63.6(h)(6)	Yes	
63.6(h)(7)	No	Subpart CC does not require opacity standards.
63.6(h)(8)	Yes	
63.6(h)(9)	No	Subpart CC does not require opacity standards.
63.6(i)	Yes	Except for §63.6(i)(15), which is reserved.
63.6(j)	Yes	
63.7(a)(1)	Yes	
63.7(a)(2)	Yes	Except test results must be submitted in the Notification of Compliance Status report due 150 days after compliance date, as specified in §63.655(f) of subpart CC.
63.7(a)(3)	Yes	
63.7(a)(4)	Yes	
63.7(b)	Yes	Except this subpart requires notification of performance test at least 30 days (rather than 60 days) prior to the performance test.
63.7(c)	No	Subpart CC does not require a site-specific test plan.
63.7(d)	Yes	
63.7(e)(1)	No	See §63.642(d)(3).
63.7(e)(2)- 63.7(e)(4)	Yes	
63.7(f)	No	Subpart CC specifies applicable methods and provides alternatives without additional notification or approval.
63.7(g)	No	Performance test reporting specified in §63.655(f).
63.7(h)(1)	Yes	
63.7(h)(2)	Yes	

Reference	**Applies to subpart CC**	**Comment**
63.7(h)(3)	Yes	Yes, except site-specific test plans shall not be required, and where §63.7(g)(3) specifies submittal by the date the site-specific test plan is due, the date shall be 90 days prior to the Notification of Compliance Status report in §63.655(f).
63.7(h)(4)(i)	Yes	
63.7(h)(4)(ii)	No	Site-specific test plans are not required in subpart CC.
63.7(h)(4)(iii) and (iv)	Yes	
63.7(h)(5)	Yes	
63.8(a)(1) and (2)	Yes.	
63.8(a)(3)	No	Reserved.
63.8(a)(4)	Yes	Except that for a flare complying with §63.670, the cross-reference to §63.11 in this paragraph does not include §63.11(b).
63.8(b)	Yes	
63.8(c)(1)	Yes	Except §63.8(c)(1)(i) and (iii).
63.8(c)(1)(i)	No	See §63.642(n).
63.8(c)(1)(iii)	No.	
63.8(c)(2)	Yes	
63.8(c)(3)	Yes	Except that verification of operational status shall, at a minimum, include completion of the manufacturer's written specifications or recommendations for installation, operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment would monitor accurately.
63.8(c)(4)	Yes	Except that for sources other than flares, this subpart specifies the monitoring cycle frequency specified in §63.8(c)(4)(ii) is “once every hour” rather than “for each successive 15-minute period.”
63.8(c)(5)-63.8(c)(8)	No	This subpart specifies continuous monitoring system requirements.
63.8(d)	No	This subpart specifies quality control procedures for continuous monitoring systems.
63.8(e)	Yes.	
63.8(f)(1)	Yes	
63.8(f)(2)	Yes	
63.8(f)(3)	Yes	
63.8(f)(4)(i)	No	Timeframe for submitting request is specified in §63.655(h)(5)(i) of subpart CC.
63.8(f)(4)(ii)	Yes	
63.8(f)(4)(iii)	No	Timeframe for submitting request is specified in §63.655(h)(5)(i) of subpart CC.
63.8(f)(5)	Yes	
63.8(f)(6)	No	Subpart CC does not require continuous emission monitors.
63.8(g)	No	This subpart specifies data reduction procedures in §§63.655(i)(3) and 63.671(d).

Reference	**Applies to subpart CC**	**Comment**
63.9(a)	Yes	Except that the owner or operator does not need to send a copy of each notification submitted to the Regional Office of the EPA as stated in §63.9(a)(4)(ii).
63.9(b)(1)	Yes	Except the notification of compliance status report specified in §63.655(f) of subpart CC may also serve as the initial compliance notification required in §63.9(b)(1)(iii).
63.9(b)(2)	No	A separate Initial Notification report is not required under subpart CC.
63.9(b)(3)	No	Reserved.
63.9(b)(4)	Yes	Except for subparagraphs §63.9(b)(4)(ii) through (iv), which are reserved.
63.9(b)(5)	Yes	
63.9(c)	Yes	
63.9(d)	Yes	
63.9(e)	No	Subpart CC requires notification of performance test at least 30 days (rather than 60 days) prior to the performance test and does not require a site-specific test plan.
63.9(f)	No	Subpart CC does not require advanced notification of visible emissions test.
63.9(g)	No	
63.9(h)	No	Subpart CC §63.655(f) specifies Notification of Compliance Status report requirements.
63.9(i)	Yes	
63.9(j)	No	
63.10(a)	Yes	
63.10(b)(1)	No	§63.655(i) of subpart CC specifies record retention requirements.
63.10(b)(2)(i)	No.	
63.10(b)(2)(ii)	No	§63.655(i) specifies the records that must be kept.
63.10(b)(2)(iii)	No	
63.10(b)(2)(iv)	No.	
63.10(b)(2)(v)	No.	
63.10(b)(2)(vi)	Yes	
63.10(b)(2)(vii)	No	§63.655(i) specifies records to be kept for parameters measured with continuous monitors.
63.10(b)(2)(viii)	Yes	
63.10(b)(2)(ix)	Yes	
63.10(b)(2)(x)	Yes	
63.10(b)(2)(xi)	No	
63.10(b)(2)(xii)	Yes	
63.10(b)(2)(xiii)	No	
63.10(b)(2)(xiv)	Yes	
63.10(b)(3)	No	

Reference	Applies to subpart CC	Comment
63.10(c)(1)-63.10(c)(6)	No	
63.10(c)(7) and 63.10(c)(8)	Yes	
63.10(c)(9)	No	Reserved.
63.10(c)(10)-63.10(c)(11)	No	§63.655(i) specifies the records that must be kept.
63.10(c)(12)-63.10(c)(15)	No.	
63.10(d)(1)	Yes	
63.10(d)(2)	No	Although §63.655(f) specifies performance test reporting, EPA may approve other timeframes for submittal of performance test data.
63.10(d)(3)	No	Results of visible emissions test are included in Compliance Status Report as specified in §63.655(f).
63.10(d)(4)	Yes	
63.10(d)(5)	No	§63.655(g) specifies the reporting requirements.
63.10(e)	No	
63.10(f)	Yes	
63.11	Yes	Except that flares complying with §63.670 are not subject to the requirements of §63.11(b).
63.12-63.16	Yes.	

[a] Wherever subpart A of this part specifies “postmark” dates, submittals may be sent by methods other than the U.S. Mail (*e.g.,* by fax or courier). Submittals shall be sent by the specified dates, but a postmark is not required.

Table 7—Fraction Measured (FM), Fraction Emitted (FE), and Fraction Removed (FR) for HAP Compounds in Wastewater Streams

Chemical name	CAS No.[a]	F_m	F_e	Fr
Benzene	71432	1.00	0.80	0.99
Biphenyl	92524	0.86	0.45	0.99
Butadiene (1,3)	106990	1.00	0.98	0.99
Carbon disulfide	75150	1.00	0.92	0.99
Cumene	98828	1.00	0.88	0.99
Dichloroethane (1,2-) (Ethylene dichloride)	107062	1.00	0.64	0.99
Ethylbenzene	100414	1.00	0.83	0.99
Hexane	110543	1.00	1.00	0.99
Methanol	67561	0.85	0.17	0.31
Methyl isobutyl ketone (hexone)	108101	0.98	0.53	0.99

Chemical name	CAS No.[a]	F_m	F_e	Fr
Methyl tert butyl ether	1634044	1.00	0.57	0.99
Naphthalene	91203	0.99	0.51	0.99
Trimethylpentane (2,2,4)	540841	1.00	1.00	0.99
xylene (m-)	108383	1.00	0.82	0.99
xylene (o-)	95476	1.00	0.79	0.99
xylene (p-)	106423	1.00	0.82	0.99

[a] CAS numbers refer to the Chemical Abstracts Service registry number assigned to specific compounds, isomers, or mixtures of compounds.

Table 8—Valve Monitoring Frequency for Phase III

Performance level	
Leaking valves[a] (%)	Valve monitoring frequency
≥4	Monthly or QIP.[b]
<4	Quarterly.
<3	Semiannual.
<2	Annual.

[a] Percent leaking valves is calculated as a rolling average of two consecutive monitoring periods.

[b] QIP = Quality improvement program. Specified in §63.175 of subpart H of this part.

Table 9—Valve Monitoring Frequency for Alternative

Performance level	
Leaking valves[a] (%)	Valve monitoring frequency under §63.649 alternative
≥5	Monthly or QIP.[b]
<5	Quarterly.
<4	Semiannual.
<3	Annual.

[a] Percent leaking valves is calculated as a rolling average of two consecutive monitoring periods.

[b] QIP = Quality improvement program. Specified in §63.175 of subpart H of this part.

Table 10—Miscellaneous Process Vents—Monitoring, Recordkeeping and Reporting Requirements for Complying With 98 Weight-Percent Reduction of Total Organic HAP Emissions or a Limit of 20 Parts Per Million by Volume

Control device	**Parameters to be monitored**[a]	**Recordkeeping and reporting requirements for monitored parameters**
Thermal incinerator	Firebox temperature[b] (63.644(a)(1)(i))	1. Continuous records[c].
		2. Record and report the firebox temperature averaged over the full period of the performance test—NCS[d].
		3. Record the daily average firebox temperature for each operating day[e].
		4. Report all daily average temperatures that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected[f]—PR[g].
Catalytic incinerator	Temperature upstream and downstream of the catalyst bed (63.644(a)(1)(ii))	1. Continuous records[c].
		2. Record and report the upstream and downstream temperatures and the temperature difference across the catalyst bed averaged over the full period of the performance test—NCS[d].
		3. Record the daily average upstream temperature and temperature difference across the catalyst bed for each operating day[e].
		4. Report all daily average upstream temperatures that are outside the range established in the NCS or operating permit—PR[g].
		5. Report all daily average temperature differences across the catalyst bed that are outside the range established in the NCS or operating permit—PR[g].
		6. Report all operating days when insufficient monitoring data are collected[f].
Boiler or process heater with a design heat capacity less than 44 megawatts where the vent stream is *not* introduced into the flame zone[h i]	Firebox temperature[b] (63.644(a)(4))	1. Continuous records[c].
		2. Record and report the firebox temperature averaged over the full period of the performance test—NCS[d].
		3. Record the daily average firebox temperature for each operating day[e].
		4. Report all daily average firebox temperatures that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected[f]—PR[g].

Control device	**Parameters to be monitored**[a]	**Recordkeeping and reporting requirements for monitored parameters**
Flare (if meeting the requirements of §§63.643 and 63.644)	Presence of a flame at the pilot light (63.644(a)(2))	1. Hourly records of whether the monitor was continuously operating and whether a pilot flame was continuously present during each hour.
		2. Record and report the presence of a flame at the pilot light over the full period of the compliance determination—NCS[d].
		3. Record the times and durations of all periods when all pilot flames for a flare are absent or the monitor is not operating.
		4. Report the times and durations of all periods when all pilot flames for a flare are absent or the monitor is not operating.
Flare (if meeting the requirements of §§63.670 and 63.671)	The parameters specified in §63.670	1. Records as specified in §63.655(i)(9). 2. Report information as specified in §63.655(g)(11)—PR.[g]
All control devices	Presence of flow diverted to the atmosphere from the control device (§63.644(c)(1)) *or*	1. Hourly records of whether the flow indicator was operating and whether flow was detected at any time during each hour. Record and report the times and durations of all periods when the vent stream is diverted through a bypass line or the monitor is not operating—PR.[g]
	Monthly inspections of sealed valves (§63.644(c)(2))	1. Records that monthly inspections were performed. 2. Record and report all monthly inspections that show the valves are not closed or the seal has been changed—PR.[g]

[a] Regulatory citations are listed in parentheses.

[b] Monitor may be installed in the firebox or in the ductwork immediately downstream of the firebox before any substantial heat exchange is encountered.

[c] "Continuous records" is defined in §63.641.

[d] NCS = Notification of Compliance Status Report described in §63.655.

[e] The daily average is the average of all recorded parameter values for the operating day. If all recorded values during an operating day are within the range established in the NCS or operating permit, a statement to this effect can be recorded instead of the daily average.

[f] When a period of excess emission is caused by insufficient monitoring data, as described in §63.655(g)(6)(i)(C) or (D), the duration of the period when monitoring data were not collected shall be included in the Periodic Report.

[g] PR = Periodic Reports described in §63.655(g).

[h] No monitoring is required for boilers and process heaters with a design heat capacity ≥44 megawatts or for boilers and process heaters where all vent streams are introduced into the flame zone. No recordkeeping or reporting associated with monitoring is required for such boilers and process heaters.

[i] Process vents that are routed to refinery fuel gas systems are not regulated under this subpart provided that on and after January 30, 2019, any flares receiving gas from that fuel gas system are in compliance with §63.670. No monitoring, recordkeeping, or reporting is required for boilers and process heaters that combust refinery fuel gas.

Table 11—Compliance Dates and Requirements

If the construction/ reconstruction date is . . .	Then the owner or operator must comply with . . .	And the owner or operator must achieve compliance . . .	Except as provided in . . .
(1) After June 30, 2014	(i) Requirements for new sources in §§63.643(a) and (b); 63.644, 63.645, and 63.647; 63.648(a) through (i) and (j)(1) and (2); 63.649 through 63.651; and 63.654 through 63.656	Upon initial startup	§63.640(k), (l) and (m).
	(ii) Requirements for new sources in §§63.642(n), 63.643(c), 63.648(j)(3), (6) and (7); and 63.657 through 63.660	Upon initial startup or February 1, 2016, whichever is later	§63.640(k), (l) and (m).
(2) After September 4, 2007 but on or before June 30, 2014	(i) Requirements for new sources in §§63.643(a) and (b); 63.644, 63.645, and 63.647; 63.648(a) through (i) and (j)(1) and (2); and 63.649 through 63.651, 63.655 and 63.656	Upon initial startup	§63.640(k), (l) and (m).
	(ii) Requirements for new sources in §63.654	Upon initial startup or October 28, 2009, whichever is later	§63.640(k), (l) and (m).
	(iii) Requirements for new sources in either §63.646 or §63.660 or, if applicable, §63.640(n)	Upon initial startup, but you must transition to comply with only the requirements in §63.660 or, if applicable, §63.640(n) on or before April 29, 2016	§§63.640(k), (l) and (m) and 63.660(d).
	(iv) Requirements for existing sources in §63.643(c)	On or before August 1, 2017	§§63.640(k), (l) and (m) and 63.643(d).
	(v) Requirements for existing sources in §63.658	On or before January 30, 2018	§63.640(k), (l) and (m).
	(vi) Requirements for existing sources in §63.648 (j)(3), (6) and (7) and §63.657	On or before January 30, 2019	§63.640(k), (l) and (m).
	(vii) Requirements in §63.642 (n)	Upon initial startup or February 1, 2016, whichever is later	
(3) After July 14, 1994 but on or before September 4, 2007	(i) Requirements for new sources in §§63.643(a) and (b); 63.644, 63.645, and 63.647; 63.648(a) through (i) and (j)(1) and (2); and 63.649 through 63.651, 63.655 and 63.656	Upon initial startup or August 18, 1995, whichever is later	§63.640(k), (l) and (m).
	(ii) Requirements for existing sources in §63.654	On or before October 29, 2012	§63.640(k), (l) and (m).

If the construction/ reconstruction date is . . .	**Then the owner or operator must comply with . . .**	**And the owner or operator must achieve compliance . . .**	**Except as provided in . . .**
	(iii) Requirements for new sources in either §63.646 or §63.660 or, if applicable, §63.640(n)	Upon initial startup, but you must transition to comply with only the requirements in §63.660 or, if applicable, §63.640(n) on or before April 29, 2016	§§63.640(k), (l) and (m) and 63.660(d).
	(iv) Requirements for existing sources in §63.643(c)	On or before August 1, 2017	§§63.640(k), (l) and (m) and 63.643(d).
	(v) Requirements for existing sources in §63.658	On or before January 30, 2018	§63.640(k), (l) and (m).
	(vi) Requirements for existing sources in §§63.648(j)(3), (6) and (7) and 63.657	On or before January 30, 2019	§63.640(k), (l) and (m).
	(vii) Requirements in §63.642(n)	Upon initial startup or February 1, 2016, whichever is later	
(4) On or before July 14, 1994	(i) Requirements for existing sources in §§63.648(a) through (i) and (j)(1) and (2); and 63.649, 63.655 and 63.656	(A) On or before August 18, 1998	(*1*) §63.640(k), (l) and (m). (*2*) §63.6(c)(5) or unless an extension has been granted by the Administrator as provided in §63.6(i).
	(ii) Either the requirements for existing sources in §§63.643(a) and (b); 63.644, 63.645, 63.647, 63.650 and 63.651; and item (4)(v) of this table OR The requirements in §§63.652 and 63.653	(A) On or before August 18, 1998	(*1*) §63.640(k), (l) and (m). (*2*) §63.6(c)(5) or unless an extension has been granted by the Administrator as provided in §63.6(i).
	(iii) Requirements for existing sources in either §63.646 or §63.660 or, if applicable, §63.640(n)	On or before August 18, 1998, but you must transition to comply with only the requirements in §63.660 or, if applicable, §63.640(n) on or before April 29, 2016	§§63.640(k), (l) and (m) and 63.660(d).
	(iv) Requirements for existing sources in §63.654	On or before October 29, 2012	§63.640(k), (l) and (m).
	(v) Requirements for existing sources in §63.643(c)	On or before August 1, 2017	§§63.640(k), (l) and (m) and 63.643(d).
	(vi) Requirements for existing sources in §63.658	On or before January 30, 2018	§63.640(k), (l) and (m).
	(vii) Requirements for existing sources in §§63.648(j)(3), (6) and (7) and 63.657	On or before January 30, 2019	§63.640(k), (l) and (m).
	(viii) Requirements in §63.642 (n)	Upon initial startup or February 1, 2016, whichever is later	

Table 12—Individual Component Properties

Component	Molecular formula	MW_i (pounds per pound-mole)	CMN_i (mole per mole)	NHV_i (British thermal units per standard cubic foot)	LFL_i (volume %)
Acetylene	C_2H_2	26.04	2	1,404	2.5
Benzene	C_6H_6	78.11	6	3,591	1.3
1,2-Butadiene	C_4H_6	54.09	4	2,794	2.0
1,3-Butadiene	C_4H_6	54.09	4	2,690	2.0
iso-Butane	C_4H_{10}	58.12	4	2,957	1.8
n-Butane	C_4H_{10}	58.12	4	2,968	1.8
cis-Butene	C_4H_8	56.11	4	2,830	1.6
iso-Butene	C_4H_8	56.11	4	2,928	1.8
trans-Butene	C_4H_8	56.11	4	2,826	1.7
Carbon Dioxide	CO_2	44.01	1	0	∞
Carbon Monoxide	CO	28.01	1	316	12.5
Cyclopropane	C_3H_6	42.08	3	2,185	2.4
Ethane	C_2H_6	30.07	2	1,595	3.0
Ethylene	C_2H_4	28.05	2	1,477	2.7
Hydrogen	H_2	2.02	0	1,212[a]	4.0
Hydrogen Sulfide	H_2S	34.08	0	587	4.0
Methane	CH_4	16.04	1	896	5.0
Methyl-Acetylene	C_3H_4	40.06	3	2,088	1.7
Nitrogen	N_2	28.01	0	0	∞
Oxygen	O_2	32.00	0	0	∞
Pentane+ (C5+)	C_5H_{12}	72.15	5	3,655	1.4
Propadiene	C_3H_4	40.06	3	2,066	2.16
Propane	C_3H_8	44.10	3	2,281	2.1
Propylene	C_3H_6	42.08	3	2,150	2.4
Water	H_2O	18.02	0	0	∞

[a] The theoretical net heating value for hydrogen is 274 Btu/scf, but for the purposes of the flare requirement in this subpart, a net heating value of 1,212 Btu/scf shall be used.

Table 13—Calibration and Quality Control Requirements for CPMS

Parameter	Minimum accuracy requirements	Calibration requirements
Temperature	±1 percent over the normal range of temperature measured, expressed in degrees Celsius (C), or 2.8 degrees C, whichever is greater	Conduct calibration checks at least annually; conduct calibration checks following any period of more than 24 hours throughout which the temperature exceeded the manufacturer's specified maximum rated temperature or install a new temperature sensor. At least quarterly, inspect all components for integrity and all electrical connections for continuity, oxidation, and galvanic corrosion, unless the CPMS has a redundant temperature sensor.
		Record the results of each calibration check and inspection.
		Locate the temperature sensor in a position that provides a representative temperature; shield the temperature sensor system from electromagnetic interference and chemical contaminants.
Flow Rate for All Flows Other Than Flare Vent Gas	±5 percent over the normal range of flow measured or 1.9 liters per minute (0.5 gallons per minute), whichever is greater, for liquid flow	Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer's specified maximum rated flow rate or install a new flow sensor.
	±5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute), whichever is greater, for gas flow	At least quarterly, inspect all components for leakage, unless the CPMS has a redundant flow sensor.
	±5 percent over the normal range measured for mass flow	Record the results of each calibration check and inspection. Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.
Flare Vent Gas Flow Rate	±20 percent of flow rate at velocities ranging from 0.03 to 0.3 meters per second (0.1 to 1 feet per second) ±5 percent of flow rate at velocities greater than 0.3 meters per second (1 feet per second)	Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer's specified maximum rated flow rate or install a new flow sensor. At least quarterly, inspect all components for leakage, unless the CPMS has a redundant flow sensor.
		Record the results of each calibration check and inspection.
		Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

Parameter	Minimum accuracy requirements	Calibration requirements
Pressure	±5 percent over the normal operating range or 0.12 kilopascals (0.5 inches of water column), whichever is greater	Review pressure sensor readings at least once a week for straightline (unchanging) pressure and perform corrective action to ensure proper pressure sensor operation if blockage is indicated. Using an instrument recommended by the sensor's manufacturer, check gauge calibration and transducer calibration annually; conduct calibration checks following any period of more than 24 hours throughout which the pressure exceeded the manufacturer's specified maximum rated pressure or install a new pressure sensor.
		At least quarterly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage, unless the CPMS has a redundant pressure sensor.
		Record the results of each calibration check and inspection.
		Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.
Net Heating Value by Calorimeter	±2 percent of span	Specify calibration requirements in your site specific CPMS monitoring plan. Calibration requirements should follow manufacturer's recommendations at a minimum. Temperature control (heated and/or cooled as necessary) the sampling system to ensure proper year-round operation.
		Where feasible, select a sampling location at least two equivalent diameters downstream from and 0.5 equivalent diameters upstream from the nearest disturbance. Select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in-leakages, or other point at which a change in the pollutant concentration or emission rate occurs.
Net Heating Value by Gas Chromatograph	As specified in Performance Specification 9 of 40 CFR part 60, appendix B	Follow the procedure in Performance Specification 9 of 40 CFR part 60, appendix B, except that a single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly), and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C).
Hydrogen analyzer	±2 percent over the concentration measured or 0.1 volume percent, whichever is greater	Specify calibration requirements in your site specific CPMS monitoring plan. Calibration requirements should follow manufacturer's recommendations at a minimum.
		Select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in-leakages, or other point at which a change in the pollutant concentration occurs.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29881, 29882, June 12, 1996; 63 FR 44142, 44143, Aug. 18, 1998; 74 FR 55688, Oct. 28, 2009; 75 FR 37731, June 30, 2010; 80 FR 75269, Dec. 1, 2015; 81 FR 45241, July 13, 2016]

Attachment O

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on January 29, 2015]

Electronic Code of Federal Regulations

Title 40: Protection of Environment +

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart WW—National Emission Standards for Storage Vessels (Tanks)—Control Level 2

Source: 64 FR 34918, June 29, 1999, unless otherwise noted.

§63.1060 Applicability.

The provisions of this subpart apply to the control of air emissions from storage vessels for which another subpart references the use of this subpart for such air emission control. These air emission standards for storage vessels are placed here for administrative convenience and only apply to those owners and operators of facilities subject to a referencing subpart. The provisions of subpart A (General Provisions) of this part do not apply to this subpart except as noted in the referencing subpart.

§63.1061 Definitions.

All terms used in this subpart shall have the meaning given them in the Act and in this section.

Capacity means the volume of liquid that is capable of being stored in a vessel, determined by multiplying the vessel's internal cross-sectional area by the internal height of the shell.

Deck cover means a device which covers an opening in a floating roof deck. Some deck covers move horizontally relative to the deck (i.e., a sliding cover).

Empty or *emptying* means the partial or complete removal of stored liquid from a storage vessel. Storage vessels that contain liquid only as wall or bottom clingage, or in pools due to bottom irregularities, are considered completely empty.

External floating roof or *EFR* means a floating roof located in a storage vessel without a fixed roof.

Fill or *filling* means the introduction of liquid into a storage vessel, but not necessarily to capacity.

Fixed roof means a roof that is mounted (i.e., permanently affixed) on a storage vessel and that does not move with fluctuations in stored liquid level.

Flexible fabric sleeve seal means a seal made of an elastomeric fabric (or other material) which covers an opening in a floating roof deck, and which allows the penetration of a fixed roof support column. The seal is attached to the rim of the deck opening and extends to the outer surface of the column. The seal is draped (but does not contact the stored liquid) to allow the horizontal movement of the deck relative to the column.

Floating roof means a roof that floats on the surface of the liquid in a storage vessel. A floating roof substantially covers the stored liquid surface (but is not necessarily in contact with the entire surface), and is comprised of a deck, a rim seal, and miscellaneous deck fittings.

Initial fill or *initial filling means* the first introduction of liquid into a storage vessel that is either newly constructed or has not been in liquid service for a year or longer.

Internal floating roof or *IFR* means a floating roof located in a storage vessel with a fixed roof. For the purposes of this subpart, an external floating roof located in a storage vessel to which a fixed roof has been added is considered to be an internal floating roof.

Liquid-mounted seal means a resilient or liquid-filled rim seal designed to contact the stored liquid.

Mechanical shoe seal or *metallic shoe seal* means a rim seal consisting of a band of metal (or other suitable material) as the sliding contact with the wall of the storage vessel, and a fabric seal to close the annular space between the band and the rim of the floating roof deck. The band is typically formed as a series of sheets (shoes) that are overlapped or joined together to form a ring. The lower end of the band extends into the stored liquid.

Pole float means a float located inside a guidepole that floats on the surface of the stored liquid. The rim of the float has a wiper or seal that extends to the inner surface of the pole.

Pole sleeve means a device which extends from either the cover or the rim of an opening in a floating roof deck to the outer surface of a pole that passes through the opening. The sleeve extends into the stored liquid.

Pole wiper means a seal that extends from either the cover or the rim of an opening in a floating roof deck to the outer surface of a pole that passes through the opening.

Referencing subpart means the subpart that refers an owner or operator to this subpart.

Rim seal means a device attached to the rim of a floating roof deck that spans the annular space between the deck and the wall of the storage vessel. When a floating roof has only one such device, it is a primary seal; when there are two seals (one mounted above the other), the lower seal is the primary seal and the upper seal is the secondary seal.

Slotted guidepole means a guidepole or gaugepole that has slots or holes through the wall of the pole. The slots or holes allow the stored liquid to flow into the pole at liquid levels above the lowest operating level.

Storage vessel or *Tank* means a stationary unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support and is designed to hold an accumulation of liquids or other materials.

Vapor-mounted seal means a rim seal designed not to be in contact with the stored liquid. Vapor-mounted seals may include, but are not limited to, resilient seals and flexible wiper seals.

§63.1062 Storage vessel control requirements.

(a) For each storage vessel to which this subpart applies, the owner or operator shall comply with one of the requirements listed in paragraphs (a)(1) through (a)(3) of this section.

(1) Operate and maintain an IFR.

(2) Operate and maintain an EFR.

(3) *Equivalent requirements.* Comply with an equivalent to the requirements in paragraph (a)(1) or (a)(2) of this section, as provided in §63.1064.

(b) [Reserved]

§63.1063 Floating roof requirements.

The owner or operator who elects to use a floating roof to comply with the requirements of §63.1062 shall comply with the requirements in paragraphs (a) through (e) of this section.

(a) *Design requirements*—(1) *Rim seals.* (i) *Internal floating roof.* An IFR shall be equipped with one of the seal configurations listed in paragraphs (a)(1)(i)(A) through (a)(1)(i)(C) of this section.

(A) A liquid-mounted seal.

(B) A mechanical shoe seal.

(C) Two seals mounted one above the other. The lower seal may be vapor-mounted.

(D) If the IFR is equipped with a vapor-mounted seal as of the proposal date for a referencing subpart, paragraphs (a)(1)(i)(A) through (a)(1)(i)(C) of this section do not apply until the next time the storage vessel is completely emptied and degassed, or 10 years after promulgation of the referencing subpart, whichever occurs first.

(ii) *External floating roof.* An EFR shall be equipped with one of the seal configurations listed in paragraphs (a)(1)(ii)(A) and (a)(1)(ii)(B) of this section.

(A) A liquid-mounted seal and a secondary seal.

(B) A mechanical shoe seal and a secondary seal. The upper end of the shoe(s) shall extend a minimum of 61 centimeters (24 inches) above the stored liquid surface.

(C) If the EFR is equipped with a liquid-mounted seal or mechanical shoe seal, or a vapor-mounted seal and secondary seal, as of the proposal date for a referencing subpart, the seal options specified in paragraphs (a)(1)(ii)(A) and (a)(1)(ii)(B) of this section do not apply until the next time the storage vessel is completely emptied and degassed, or 10 years after the promulgation date of the referencing subpart, whichever occurs first.

(2) *Deck fittings.* Openings through the deck of the floating roof shall be equipped as described in paragraphs (a)(2)(i) through (a)(2)(viii) of this section.

(i) Each opening except those for automatic bleeder vents (vacuum breaker vents) and rim space vents shall have its lower edge below the surface of the stored liquid.

(ii) Each opening except those for automatic bleeder vents (vacuum breaker vents), rim space vents, leg sleeves, and deck drains shall be equipped with a deck cover. The deck cover shall be equipped with a gasket between the cover and the deck.

(iii) Each automatic bleeder vent (vacuum breaker vent) and rim space vent shall be equipped with a gasketed lid, pallet, flapper, or other closure device.

(iv) Each opening for a fixed roof support column may be equipped with a flexible fabric sleeve seal instead of a deck cover.

(v) Each opening for a sample well or deck drain (that empties into the stored liquid) may be equipped with a slit fabric seal or similar device that covers at least 90 percent of the opening, instead of a deck cover.

(vi) Each cover on access hatches and gauge float wells shall be designed to be bolted or fastened when closed.

(vii) Each opening for an unslotted guidepole shall be equipped with a pole wiper, and each unslotted guidepole shall be equipped with a gasketed cap on the top of the guidepole.

(viii) Each opening for a slotted guidepole shall be equipped with one of the control device configurations specified in paragraphs (a)(2)(viii)(A) and (a)(2)(viii)(B) of this section.

(A) A pole wiper and a pole float. The wiper or seal of the pole float shall be at or above the height of the pole wiper.

(B) A pole wiper and a pole sleeve.

(ix) If the floating roof does not meet the requirements listed in paragraphs (a)(2)(i) through (a)(2)(viii) of this section as of the proposal date of the referencing subpart, these requirements do not apply until the next time the vessel is completely emptied and degassed, or 10 years after the promulgation date of the referencing subpart, whichever occurs first.

(b) *Operational requirements.* (1) The floating roof shall float on the stored liquid surface at all times, except when the floating roof is supported by its leg supports or other support devices (e.g., hangers from the fixed roof).

(2) When the storage vessel is storing liquid, but the liquid depth is insufficient to float the floating roof, the process of filling to the point of refloating the floating roof shall be continuous and shall be performed as soon as practical.

(3) Each cover over an opening in the floating roof, except for automatic bleeder vents (vacuum breaker vents) and rim space vents, shall be closed at all times, except when the cover must be open for access.

(4) Each automatic bleeder vent (vacuum breaker vent) and rim space vent shall be closed at all times, except when required to be open to relieve excess pressure or vacuum, in accordance with the manufacturer's design.

(5) Each unslotted guidepole cap shall be closed at all times except when gauging the liquid level or taking liquid samples.

(c) *Inspection frequency requirements*—(1) *Internal floating roofs.* Internal floating roofs shall be inspected as specified in paragraph (d)(1) of this section before the initial filling of the storage vessel. Subsequent inspections shall be performed as specified in paragraph (c)(1)(i) or (c)(1)(ii) of this section.

(i) Internal floating roofs shall be inspected as specified in paragraphs (c)(1)(i)(A) and (c)(1)(i)(B) of this section.

(A) At least once per year the IFR shall be inspected as specified in paragraph (d)(2) of this section.

(B) Each time the storage vessel is completely emptied and degassed, or every 10 years, whichever occurs first, the IFR shall be inspected as specified in paragraph (d)(1) of this section.

(ii) Instead of the inspection frequency specified in paragraph (c)(1)(i) of this section, internal floating roofs with two rim seals may be inspected as specified in paragraph (d)(1) of this section each time the storage vessel is completely emptied and degassed, or every 5 years, whichever occurs first.

(2) *External floating roofs.* External floating roofs shall be inspected as specified in paragraphs (c)(2)(i) through (c)(2)(iv) of this section.

(i) Within 90 days after the initial filling of the storage vessel, the primary and secondary rim seals shall be inspected as specified in paragraph (d)(3) of this section.

(ii) The secondary seal shall be inspected at least once every year, and the primary seal shall be inspected at least every 5 years, as specified in paragraph (d)(3) of this section.

(iii) Each time the storage vessel is completely emptied and degassed, or every 10 years, whichever occurs first, the EFR shall be inspected as specified in paragraph (d)(1) of this section.

(iv) If the owner or operator determines that it is unsafe to perform the floating roof inspections specified in paragraphs (c)(2)(i) and (c)(2)(ii) of this section, the owner or operator shall comply with the requirements of paragraph (c)(2)(iv)(A) or (c)(2)(iv)(B) of this section.

(A) The inspections shall be performed no later than 30 days after the determination that the floating roof is unsafe.

(B) The storage vessel shall be removed from liquid service no later than 45 days after determining the floating roof is unsafe. If the vessel cannot be emptied within 45 days, the owner or operator may utilize up to two extensions of up to 30 additional days each. If the vessel cannot be emptied within 45 days, the owner or operator may utilize up to two extensions of up to 30 additional days each. Documentation of a decision to use an extension shall include an explanation of why it was unsafe to perform the inspection, documentation that alternative storage capacity is unavailable, and a schedule of actions that will ensure that the vessel will be emptied as soon as practical.

(d) *Inspection procedure requirements.* Floating roof inspections shall be conducted as specified in paragraphs (d)(1) through (d)(3) of this section, as applicable. If a floating roof fails an inspection, the owner or operator shall comply with the repair requirements of paragraph (e) of this section.

(1) Floating roof (IFR and EFR) inspections shall be conducted by visually inspecting the floating roof deck, deck fittings, and rim seals from within the storage vessel. The inspection may be performed entirely from the top side of the floating roof, as long as there is visual access to all deck components specified in paragraph (a) of this section. Any of the conditions described in paragraphs (d)(1)(i) through (d)(1)(v) of this section constitutes inspection failure.

(i) Stored liquid on the floating roof.

(ii) Holes or tears in the primary or secondary seal (if one is present).

(iii) Floating roof deck, deck fittings, or rim seals that are not functioning as designed (as specified in paragraph (a) of this section).

(iv) Failure to comply with the operational requirements of paragraph (b) of this section.

(v) Gaps of more than 0.32 centimeters (⅛ inch) between any deck fitting gasket, seal, or wiper (required by paragraph (a) of this section) and any surface that it is intended to seal.

(2) Tank-top inspections of IFR's shall be conducted by visually inspecting the floating roof deck, deck fittings, and rim seal through openings in the fixed roof. Any of the conditions described in paragraphs (d)(1)(i) through (d)(1)(iv) of this section constitutes inspection failure. Identification of holes or tears in the rim seal is required only for the seal that is visible from the top of the storage vessel.

(3) Seal gap inspections for EFR's shall determine the presence and size of gaps between the rim seals and the wall of the storage vessel by the procedures specified in paragraph (d)(3)(i) of this section. Any exceedance of the gap requirements specified in paragraphs (d)(3)(ii) and (d)(3)(iii) of this section constitutes inspection failure.

(i) Rim seals shall be measured for gaps at one or more levels while the EFR is floating, as specified in paragraphs (d)(3)(i)(A) through (d)(3)(i)(F) of this section.

(A) The inspector shall hold a 0.32 centimeter (⅛ inch) diameter probe vertically against the inside of the storage vessel wall, just above the rim seal, and attempt to slide the probe down between the seal and the vessel wall. Each location where the probe passes freely (without forcing or binding against the seal) between the seal and the vessel wall constitutes a gap.

(B) The length of each gap shall be determined by inserting the probe into the gap (vertically) and sliding the probe along the vessel wall in each direction as far as it will travel freely without binding between the seal and the vessel wall. The circumferential length along which the probe can move freely is the gap length.

(C) The maximum width of each gap shall be determined by inserting probes of various diameters between the seal and the vessel wall. The smallest probe diameter should be 0.32 centimeter, and larger probes should have diameters in increments of 0.32 centimeter. The diameter of the largest probe that can be inserted freely anywhere along the length of the gap is the maximum gap width.

(D) The average width of each gap shall be determined by averaging the minimum gap width (0.32 centimeter) and the maximum gap width.

(E) The area of a gap is the product of the gap length and average gap width.

(F) The ratio of accumulated area of rim seal gaps to storage vessel diameter shall be determined by adding the area of each gap, and dividing the sum by the nominal diameter of the storage vessel. This ratio shall be determined separately for primary and secondary rim seals.

(ii) The ratio of seal gap area to vessel diameter for the primary seal shall not exceed 212 square centimeters per meter of vessel diameter (10 square inches per foot of vessel diameter), and the maximum gap width shall not exceed 3.81 centimeters (1.5 inches).

(iii) The ratio of seal gap area to vessel diameter for the secondary seal shall not exceed 21.2 square centimeters per meter (1 square inch per foot), and the maximum gap width shall not exceed 1.27 centimeters (0.5 inches), except when the secondary seal must be pulled back or removed to inspect the primary seal.

(e) *Repair requirements.* Conditions causing inspection failures under paragraph (d) of this section shall be repaired as specified in paragraph (e)(1) or (e)(2) of this section.

(1) If the inspection is performed while the storage vessel is not storing liquid, repairs shall be completed before the refilling of the storage vessel with liquid.

(2) If the inspection is performed while the storage vessel is storing liquid, repairs shall be completed or the vessel removed from service within 45 days. If a repair cannot be completed and the vessel cannot be emptied within 45 days, the owner or operator may use up to 2 extensions of up to 30 additional days each. Documentation of a decision to use an extension shall include a description of the failure, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the control equipment will be repaired or the vessel will be completely emptied as soon as practical.

§63.1064 Alternative means of emission limitation.

(a) An alternate control device may be substituted for a control device specified in §63.1063 if the alternate device has an emission factor less than or equal to the emission factor for the device specified in §63.1063. Requests for the use of alternate devices shall be made as specified in §63.1066(b)(3). Emission factors for the devices specified in §63.1063 are published in EPA Report No. AP-42, Compilation of Air Pollutant Emission Factors.

(b) Tests to determine emission factors for an alternate device shall accurately simulate conditions under which the device will operate, such as wind, temperature, and barometric pressure. Test methods that can be used to perform the testing required in this paragraph include, but are not limited to, the methods listed in paragraphs (b)(1) through (b)(3) of this section.

(1) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 19, Section 3, Part A, Wind Tunnel Test Method for the Measurement of Deck-Fitting Loss Factors for External Floating-Roof Tanks.

(2) API Manual of Petroleum Measurement Standards, Chapter 19, Section 3, Part B, Air Concentration Test Method for the Measurement of Rim Seal Loss Factors for Floating-Roof Tanks.

(3) API Manual of Petroleum Measurement Standards, Chapter 19, Section 3, Part E, Weight Loss Test Method for the Measurement of Deck-Fitting Loss Factors for Internal Floating-Roof Tanks.

(c) An alternate combination of control devices may be substituted for any combination of rim seal and deck fitting control devices specified in §63.1063 if the alternate combination emits no more than the combination specified in §63.1063. The emissions from an alternate combination of control devices shall be determined using AP-42 or as specified in paragraph (b) of this section. The emissions from a combination of control devices specified in §63.1063 shall be determined using AP-42. Requests for the use of alternate devices shall be made as specified in §63.1066(b)(3).

§63.1065 Recordkeeping requirements.

The owner or operator shall keep the records required in paragraph (a) of this section for as long as liquid is stored. Records required in paragraphs (b), (c) and (d) of this section shall be kept for at least 5 years. Records shall be kept in such a manner that they can be readily accessed within 24 hours. Records may be kept in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

(a) *Vessel dimensions and capacity.* A record shall be kept of the dimensions of the storage vessel, an analysis of the capacity of the storage vessel, and an identification of the liquid stored.

(b) *Inspection results.* Records of floating roof inspection results shall be kept as specified in paragraphs (b)(1) and (b)(2) of this section.

(1) If the floating roof passes inspection, a record shall be kept that includes the information specified in paragraphs (b)(1)(i) and (b)(1)(ii) of this section. If the floating roof fails inspection, a record shall be kept that includes the information specified in paragraphs (b)(1)(i) through (b)(1)(v) of this section.

(i) Identification of the storage vessel that was inspected.

(ii) The date of the inspection.

(iii) A description of all inspection failures.

(iv) A description of all repairs and the dates they were made.

(v) The date the storage vessel was removed from service, if applicable.

(2) A record shall be kept of EFR seal gap measurements, including the raw data obtained and any calculations performed.

(c) *Floating roof landings.* The owner or operator shall keep a record of the date when a floating roof is set on its legs or other support devices. The owner or operator shall also keep a record of the date when the roof was refloated, and the record shall indicate whether the process of refloating was continuous.

(d) An owner or operator who elects to use an extension in accordance with §63.1063(e)(2) or §63.1063(c)(2)(iv)(B) shall keep the documentation required by those paragraphs.

§63.1066 Reporting requirements.

(a) *Notification of initial startup.* If the referencing subpart requires that a notification of initial startup be filed, then the content of the notification of initial startup shall include (at a minimum) the information specified in the referencing subpart and the information specified in paragraphs (a)(1) and (a)(2) of this section.

(1) The identification of each storage vessel, its capacity and the liquid stored in the storage vessel.

(2) A statement of whether the owner or operator of the source can achieve compliance by the compliance date specified in referencing subpart.

(b) *Periodic reports.* Report the information specified in paragraphs (b)(1) through (b)(4) of this section, as applicable, in the periodic report specified in the referencing subpart.

(1) *Notification of inspection.* To provide the Administrator the opportunity to have an observer present, the owner or operator shall notify the Administrator at least 30 days before an inspection required by §§63.1063(d)(1) or (d)(3). If an inspection is unplanned and the owner or operator could not have known about the inspection 30 days in advance, then the owner or operator shall notify the Administrator at least 7 days before the inspection. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, the notification including the written documentation may be made in writing and sent so that it is received by the Administrator at least 7 days before the inspection. If a delegated State or local agency is notified, the owner or operator is not required to notify the Administrator. A delegated State or local agency may waive the requirement for notification of inspections.

(2) *Inspection results.* The owner or operator shall submit a copy of the inspection record (required in §63.1065) when inspection failures occur.

(3) *Requests for alternate devices.* The owner or operator requesting the use of an alternate control device shall submit a written application including emissions test results and an analysis demonstrating that the alternate device has an emission factor that is less than or equal to the device specified in §63.1063.

(4) Requests for extensions. An owner or operator who elects to use an extension in accordance with §63.1063(e)(2) or §63.1063(c)(2)(iv)(B) shall submit the documentation required by those paragraphs.

§63.1067 Implementation and enforcement.

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

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under section 40 CFR part 63, subpart E, the authorities contained 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.

(1) Approval of alternatives to the nonopacity emissions standards in §§63.1062 and 63.1063(a) and (b) for alternative means of emission limitation, under §63.6(g).

(2) [Reserved]

(3) Approval of major changes to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

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

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

[67 FR 46279, July 12, 2002]

Attachment P

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on July 19, 2016]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart UUU—National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

Source: 67 FR 17773, Apr. 11, 2002, unless otherwise noted.

What This Subpart Covers

§63.1560 What is the purpose of this subpart?

This subpart establishes national emission standards for hazardous air pollutants (HAP) emitted from petroleum refineries. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§63.1561 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate a petroleum refinery that is located at a major source of HAP emissions.

(1) A petroleum refinery is an establishment engaged primarily in petroleum refining as defined in the Standard Industrial Classification (SIC) code 2911 and the North American Industry Classification (NAIC) code 32411, and used mainly for:

(i) Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants;

(ii) Separating petroleum; or

(iii) Separating, cracking, reacting, or reforming an intermediate petroleum stream, or recovering a by-product(s) from the intermediate petroleum stream (e.g., sulfur recovery).

(2) A major source of HAP is a plant site that emits or has the potential to emit any single HAP at a rate of 9.07 megagrams (10 tons) or more per year or any combination of HAP at a rate of 22.68 megagrams (25 tons) or more per year.

(b) [Reserved]

§63.1562 What parts of my plant are covered by this subpart?

(a) This subpart applies to each new, reconstructed, or existing affected source at a petroleum refinery.

(b) The affected sources are:

(1) The process vent or group of process vents on fluidized catalytic cracking units that are associated with regeneration of the catalyst used in the unit (*i.e.*, the catalyst regeneration flue gas vent).

(2) The process vent or group of process vents on catalytic reforming units (including but not limited to semi-regenerative, cyclic, or continuous processes) that are associated with regeneration of the catalyst used in the unit. This affected source includes vents that are used during the unit depressurization, purging, coke burn, and catalyst rejuvenation.

(3) The process vent or group of process vents on Claus or other types of sulfur recovery plant units or the tail gas treatment units serving sulfur recovery plants that are associated with sulfur recovery.

(4) Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit. This means each vent system that contains a bypass line (e.g., ductwork) that could divert an affected vent stream away from a control device used to comply with the requirements of this subpart.

(c) An affected source is a new affected source if you commence construction of the affected source after September 11, 1998, and you meet the applicability criteria in §63.1561 at the time you commenced construction.

(d) Any affected source is reconstructed if you meet the criteria in §63.2.

(e) An affected source is existing if it is not new or reconstructed.

(f) This subpart does not apply to:

(1) A thermal catalytic cracking unit.

(2) A sulfur recovery unit that does not recover elemental sulfur or where the modified reaction is carried out in a water solution which contains a metal ion capable of oxidizing the sulfide ion to sulfur (e.g., the LO-CAT II process).

(3) A redundant sulfur recovery unit not located at a petroleum refinery and used by the refinery only for emergency or maintenance backup.

(4) Equipment associated with bypass lines such as low leg drains, high point bleed, analyzer vents, open-ended valves or lines, or pressure relief valves needed for safety reasons.

(5) Gaseous streams routed to a fuel gas system, provided that on and after January 30, 2019, any flares receiving gas from the fuel gas system are subject to §63.670.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6938, Feb. 9, 2005; 80 FR 75273, Dec. 1, 2015]

§63.1563 When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to the requirements in paragraphs (a)(1) and (2) of this section.

(1) If you startup your affected source before April 11, 2002, then you must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart no later than April 11, 2002 except as provided in paragraph (d) of this section.

(2) If you startup your affected source after April 11, 2002, you must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart upon startup of your affected source except as provided in paragraph (d) of this section.

(b) If you have an existing affected source, you must comply with the emission limitations and work practice standards for existing affected sources in this subpart by no later than April 11, 2005 except as specified in paragraphs (c) and (d) of this section.

(c) We will grant an extension of compliance for an existing catalytic cracking unit allowing additional time to meet the emission limitations and work practice standards for catalytic cracking units in §§63.1564 and 63.1565 if you commit to hydrotreating the catalytic cracking unit feedstock and to meeting the emission limitations of this subpart on the same date that your facility meets the final Tier 2 gasoline sulfur control standard (40 CFR part 80, subpart J). To obtain an extension, you must submit a written notification to your permitting authority according to the requirements in §63.1574(e). Your notification must include the information in paragraphs (c)(1) and (2) of this section.

(1) Identification of the affected source with a brief description of the controls to be installed (if needed) to comply with the emission limitations for catalytic cracking units in this subpart.

(2) A compliance schedule, including the information in paragraphs (c)(2)(i) through (iv) of this section.

(i) The date by which onsite construction or the process change is to be initiated.

(ii) The date by which onsite construction or the process change is to be completed.

(iii) The date by which your facility will achieve final compliance with both the final Tier 2 gasoline sulfur control standard as specified in §80.195, and the emission limitations and work practice standards for catalytic cracking units in this subpart. In no case will your permitting authority grant an extension beyond the date you are required to meet the Tier 2 gasoline sulfur control standard or December 31, 2009, whichever comes first. If you don't comply with the emission limitations and work practice standards for existing catalytic cracking units by the specified date, you will be out-of-compliance with the requirements for catalytic cracking units beginning April 11, 2005.

(iv) A brief description of interim emission control measures that will be taken to ensure proper operation and maintenance of the process equipment during the period of the compliance extension.

(d) You must comply with the applicable requirements in §§63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4) as specified in paragraph (d)(1) or (2) of this section, as applicable.

(1) For sources which commenced construction or reconstruction before June 30, 2014, you must comply with the applicable requirements in §§63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4) on or before August 1, 2017 unless an extension is requested and approved in accordance with the provisions in §63.6(i). After February 1, 2016 and prior to the date of compliance with the provisions in §§63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4), you must comply with the requirements in §63.1570(c) and (d).

(2) For sources which commenced construction or reconstruction on or after June 30, 2014, you must comply with the applicable requirements in §§63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4) on or before February 1, 2016 or upon startup, whichever is later.

(e) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the requirements in paragraphs (e)(1) and (2) of this section apply.

(1) Any portion of the existing facility that is a new affected source or a new reconstructed source must be in compliance with the requirements of this subpart upon startup.

(2) All other parts of the source must be in compliance with the requirements of this subpart by no later than 3 years after it becomes a major source or, if applicable, the extended compliance date granted according to the requirements in paragraph (c) of this section.

(f) You must meet the notification requirements in §63.1574 according to the schedule in §63.1574 and in 40 CFR part 63, subpart A. Some of the notifications must be submitted before the date you are required to comply with the emission limitations and work practice standards in this subpart.

[67 FR 17773, Apr. 11, 2002, as amended at 81 FR 45243, July 13, 2016]

Catalytic Cracking Units, Catalytic Reforming Units, Sulfur Recovery Units, and Bypass Lines

§63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?

(a) What emission limitations and work practice standards must I meet? You must:

(1) Except as provided in paragraph (a)(5) of this section, meet each emission limitation in table 1 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for PM in §60.102 of this chapter or is subject to §60.102a(b)(1) of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit is not subject to the NSPS for PM, you can choose from the six options in paragraphs (a)(1)(i) through (vi) of this section:

(i) You can elect to comply with the NSPS for PM in §60.102 of this chapter (Option 1a);

(ii) You can elect to comply with the NSPS for PM coke burn-off emission limit in §60.102a(b)(1) of this chapter (Option 1b);

(iii) You can elect to comply with the NSPS for PM concentration limit in §60.102a(b)(1) of this chapter (Option 1c);

(iv) You can elect to comply with the PM per coke burn-off emission limit (Option 2);

(v) You can elect to comply with the Nickel (Ni) lb/hr emission limit (Option 3); or

(vi) You can elect to comply with the Ni per coke burn-off emission limit (Option 4).

(2) Comply with each operating limit in Table 2 of this subpart that applies to you. When a specific control device may be monitored using more than one continuous parameter monitoring system, you may select the parameter with which you will comply. You must provide notice to the Administrator (or other designated authority) if you elect to change the monitoring option.

(3) 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.

(4) The emission limitations and operating limits for metal HAP emissions from catalytic cracking units required in paragraphs (a)(1) and (2) of this section do not apply during periods of planned maintenance preapproved by the applicable permitting authority according to the requirements in §63.1575(j).

(5) On or before the date specified in §63.1563(d), you must comply with one of the two options in paragraphs (a)(5)(i) and (ii) of this section during periods of startup, shutdown and hot standby:

(i) You can elect to comply with the requirements in paragraphs (a)(1) and (2) of this section, except catalytic cracking units controlled using a wet scrubber must maintain only the liquid to gas ratio operating limit (the pressure drop operating limit does not apply); or

(ii) You can elect to maintain the inlet velocity to the primary internal cyclones of the catalytic cracking unit catalyst regenerator at or above 20 feet per second.

(b) How do I demonstrate initial compliance with the emission limitations and work practice standard? You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in §63.1572 and Table 3 of this subpart.

(2) Conduct a performance test for each catalytic cracking unit according to the requirements in §63.1571 and under the conditions specified in Table 4 of this subpart.

(3) Establish each site-specific operating limit in Table 2 of this subpart that applies to you according to the procedures in Table 4 of this subpart.

(4) Use the procedures in paragraphs (b)(4)(i) through (iv) of this section to determine initial compliance with the emission limitations.

(i) If you elect Option 1b or Option 2 in paragraph (a)(1)(ii) or (iv) of this section, compute the PM emission rate (lb/1,000 lb of coke burn-off) for each run using Equations 1, 2, and 3 (if applicable) of this section and the site-specific opacity limit, if applicable, using Equation 4 of this section as follows:

$$R_c = K_1 Q_r(\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r\left[\left(\frac{\%CO}{2}\right) + \%CO_2 + \%O_2\right] + K_3 Q_{oxy}(\%O_{xy}) \quad \text{(Eq. 1)}$$

Where:

R_c = Coke burn-off rate, kg/hr (lb/hr);

Q_r = Volumetric flow rate of exhaust gas from catalyst regenerator before adding air or gas streams. Example: You may measure upstream or downstream of an electrostatic precipitator, but you must measure upstream of a carbon monoxide boiler, dscm/min (dscf/min). You may use the alternative in either §63.1573(a)(1) or (2), as applicable, to calculate Qr;

Q_a = Volumetric flow rate of air to catalytic cracking unit catalyst regenerator, as determined from instruments in the catalytic cracking unit control room, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide concentration in regenerator exhaust, percent by volume (dry basis);

%CO = Carbon monoxide concentration in regenerator exhaust, percent by volume (dry basis);

$\%O_2$ = Oxygen concentration in regenerator exhaust, percent by volume (dry basis);

K_1 = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) (0.0186 (lb-min)/(hr-dscf-%));

K_2 = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) (0.1303 (lb-min)/(hr-dscf));

K_3 = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) (0.0062 (lb-min)/(hr-dscf-%));

Q_{oxy} = Volumetric flow rate of oxygen-enriched air stream to regenerator, as determined from instruments in the catalytic cracking unit control room, dscm/min (dscf/min); and

$\%O_{xy}$ = Oxygen concentration in oxygen-enriched air stream, percent by volume (dry basis).

$$E = \frac{K \times C_s \times Q_{sd}}{R_c} \quad \text{(Eq. 2)}$$

Where:

E = Emission rate of PM, kg/1,000 kg (lb/1,000 lb) of coke burn-off;

C_s = Concentration of PM, g/dscm (lb/dscf);

Q_{sd} = Volumetric flow rate of the catalytic cracking unit catalyst regenerator flue gas as measured by Method 2 in appendix A-1 to part 60 of this chapter, dscm/hr (dscf/hr);

R_c = Coke burn-off rate, kg coke/hr (1,000 lb coke/hr); and

K = Conversion factor, 1.0 (kg^2/g)/(1,000 kg) (1,000 lb/(1,000 lb)).

$$E_s = 1.0 + A\left(\frac{H}{R_c}\right)K' \qquad \text{(Eq. 3)}$$

Where:

E_s = Emission rate of PM allowed, kg/1,000 kg (1b/1,000 lb) of coke burn-off in catalyst regenerator;

1.0 = Emission limitation, kg coke/1,000 kg (lb coke/1,000 lb);

A = Allowable incremental rate of PM emissions. Before August 1, 2017, A = 0.18 g/million cal (0.10 lb/million Btu). On or after August 1, 2017, A = 0 g/million cal (0 lb/million Btu);

H = Heat input rate from solid or liquid fossil fuel, million cal/hr (million Btu/hr). Make sure your permitting authority approves procedures for determining the heat input rate;

R_c = Coke burn-off rate, kg coke/hr (1,000 lb coke/hr) determined using Equation 1 of this section; and

K′ = Conversion factor to units to standard, 1.0 (kg_2/g)/(1,000 kg) (10_3 lb/(1,000 lb)).

$$Opacity\ Limit = Opacity_{st} \times \left(\frac{1\text{ lb} / 1000\text{ lb coke burn}}{PMEmR_{st}}\right) \qquad \text{(Eq. 4)}$$

Where:

Opacity Limit = Maximum permissible hourly average opacity, percent, or 10 percent, whichever is greater;

$Opacity_{st}$ = Hourly average opacity measured during the source test, percent; and

$PMEmR_{st}$ = PM emission rate measured during the source test, lb/1,000 lb coke burn.

(ii) If you elect Option 1c in paragraph (a)(1)(iii) of this section, the PM concentration emission limit, determine the average PM concentration from the initial performance test used to certify your PM CEMS.

(iii) If you elect Option 3 in paragraph (a)(1)(iii) of this section, the Ni lb/hr emission limit, compute your Ni emission rate using Equation 5 of this section and your site-specific Ni operating limit (if you use a continuous opacity monitoring system) using Equations 6 and 7 of this section as follows:

$$E_{Ni_1} = C_{Ni} \times Q_{sd} \qquad (Eq.\ 5)$$

Where:

E_{Ni1} = Mass emission rate of Ni, mg/hr (lb/hr); and

C_{Ni} = Ni concentration in the catalytic cracking unit catalyst regenerator flue gas as measured by Method 29 in appendix A to part 60 of this chapter, mg/dscm (lbs/dscf).

$$Opacity_1 = \frac{13 \text{ g Ni/hr}}{\text{NiEmR1}_{st}} \times Opacity_{st} \qquad (Eq.\ 6)$$

Where:

$Opacity_1$ = Opacity value for use in Equation 7 of this section, percent, or 10 percent, whichever is greater; and

$NiEmR1_{st}$ = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 5 of this section for each of the performance test runs, g Ni/hr.

$$Ni \textbf{ Operating Limit}_1 = Opacity_1 \times Q_{mon,st} \times E\text{-}Cat_{st} \qquad (Eq.\ 7)$$

Where:

Ni operating $limit_1$ = Maximum permissible hourly average Ni operating limit, percent-acfm-ppmw, i.e., your site-specific Ni operating limit;

$Q_{mon,st}$ = Hourly average actual gas flow rate as measured by the continuous parameter monitoring system during the performance test or using the alternative procedure in §63.1573, acfm; and

$E\text{-}Cat_{st}$ = Ni concentration on equilibrium catalyst measured during source test, ppmw.

(iv) If you elect Option 4 in paragraph (a)(1)(vi) of this section, the Ni per coke burn-off emission limit, compute your Ni emission rate using Equations 1 and 8 of this section and your site-specific Ni operating limit (if you use a continuous opacity monitoring system) using Equations 9 and 10 of this section as follows:

$$E_{Ni_2} = \frac{C_{Ni} \times Q_{sd}}{R_c} \qquad (Eq.\ 8)$$

Where:

E_{Ni2} = Normalized mass emission rate of Ni, mg/kg coke (lb/1,000 lb coke).

$$Opacity_2 = \frac{1.0 \text{ mg/kg coke}}{NiEmR2_{st}} \times Opacity_{st} \qquad (Eq.\ 9)$$

Where:

$Opacity_2$ = Opacity value for use in Equation 10 of this section, percent, or 10 percent, whichever is greater; and

$NiEmR2_{st}$ = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 8 of this section for each of the performance test runs, mg/kg coke.

$$Ni\ Operating\ Limit_2 = Opacity_2 \times E\text{-}Cat_{st} \times \frac{Q_{mon,st}}{R_{c,st}} \qquad (Eq.\ 10)$$

Where:

Ni Operating $Limit_2$ = Maximum permissible hourly average Ni operating limit, percent-ppmw-acfm-hr/kg coke, i.e., your site-specific Ni operating limit; and

$R_{c,st}$ = Coke burn rate from Equation 1 of this section, as measured during the initial performance test, kg coke/hr.

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

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting your operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(7) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 1 and 2 of this subpart that applies to you according to the methods specified in Tables 6 and 7 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by maintaining records to document conformance with the procedures in your operation, maintenance, and monitoring plan.

(3) If you use a continuous opacity monitoring system and elect to comply with Option 3 in paragraph (a)(1)(iii) of this section, determine continuous compliance with your site-specific Ni operating limit by using Equation 11 of this section as follows:

$$Ni \text{ Operating Value}_1 = Opacity \times Q_{mon} \times E\text{-}Cat \qquad (Eq.\ 11)$$

Where:

Ni operating value$_1$ = Maximum permissible hourly average Ni standard operating value, %-acfm-ppmw;

Opacity = Hourly average opacity, percent;

Q_{mon} = Hourly average actual gas flow rate as measured by continuous parameter monitoring system or calculated by alternative procedure in §63.1573, acfm; and

E-Cat = Ni concentration on equilibrium catalyst from weekly or more recent measurement, ppmw.

(4) If you use a continuous opacity monitoring system and elect to comply with Option 4 in paragraph (a)(1)(iv) of this section, determine continuous compliance with your site-specific Ni operating limit by using Equation 12 of this section as follows:

$$Ni \text{ Operating Value}_2 = \frac{Opacity \times E\text{-}Cat \times Q_{mon}}{R_c} \qquad (Eq.\ 12)$$

Where:

Ni operating value$_2$ = Maximum permissible hourly average Ni standard operating value, percent-acfm-ppmw-hr/kg coke.

(5) If you elect to comply with the alternative limit in paragraph (a)(5)(ii) of this section during periods of startup, shutdown and hot standby, demonstrate continuous compliance on or before the date specified in §63.1563(d) by:

(i) Collecting the volumetric flow rate from the catalyst regenerator (in acfm) and determining the average flow rate for each hour. For events lasting less than one hour, determine the average flow rate during the event.

(ii) Determining the cumulative cross-sectional area of the primary internal cyclone inlets in square feet (ft^2) using design drawings of the primary (first-stage) internal cyclones to determine the inlet cross-sectional area of each primary internal cyclone and summing the cross-sectional areas for all primary internal cyclones in the catalyst regenerator or, if primary cyclones. If all primary internal cyclones are identical, you may alternatively determine the inlet cross-sectional area of one primary internal cyclone using design drawings and multiply that area by the total number of primary internal cyclones in the catalyst regenerator.

(iii) Calculating the inlet velocity to the primary internal cyclones in square feet per second (ft^2/sec) by dividing the average volumetric flow rate (acfm) by the cumulative cross-sectional area of the primary internal cyclone inlets (ft^2) and by 60 seconds/minute (for unit conversion).

(iv) Maintaining the inlet velocity to the primary internal cyclones at or above 20 feet per second for each hour during the startup, shutdown, or hot standby event or, for events lasting less than 1 hour, for the duration of the event.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6938, Feb. 9, 2005; 80 FR 75273, Dec. 1, 2015; 81 FR 45243, July 13, 2016]

§63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?

(a) What emission limitations and work practice standards must I meet? You must:

(1) Except as provided in paragraph (a)(5) of this section, meet each emission limitation in Table 8 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for carbon monoxide (CO) in §60.103 of this chapter or is subject to §60.102a(b)(4) of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit is not subject to the NSPS for CO, you can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to comply with the NSPS requirements (Option 1); or

(ii) You can elect to comply with the CO emission limit (Option 2).

(2) Comply with each site-specific operating limit in Table 9 of this subpart that applies to you.

(3) 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.

(4) The emission limitations and operating limits for organic HAP emissions from catalytic cracking units required in paragraphs (a)(1) and (2) of this section do not apply during periods of planned maintenance preapproved by the applicable permitting authority according to the requirements in §63.1575(j).

(5) On or before the date specified in §63.1563(d), you must comply with one of the two options in paragraphs (a)(5)(i) and (ii) of this section during periods of startup, shutdown and hot standby:

(i) You can elect to comply with the requirements in paragraphs (a)(1) and (2) of this section; or

(ii) You can elect to maintain the oxygen (O_2) concentration in the exhaust gas from your catalyst regenerator at or above 1 volume percent (dry basis).

(b) How do I demonstrate initial compliance with the emission limitations and work practice standards? You must:

(1) Install, operate, and maintain a continuous monitoring system according to the requirements in §63.1572 and Table 10 of this subpart. Except:

(i) Whether or not your catalytic cracking unit is subject to the NSPS for CO in §60.103 of this chapter, you don't have to install and operate a continuous emission monitoring system if you show that CO emissions from your vent average less than 50 parts per million (ppm), dry basis. You must get an exemption from your permitting authority, based on your written request. To show that the emissions average is less than 50 ppm (dry basis), you must continuously monitor CO emissions for 30 days using a CO continuous emission monitoring system that meets the requirements in §63.1572.

(ii) If your catalytic cracking unit isn't subject to the NSPS for CO, you don't have to install and operate a continuous emission monitoring system or a continuous parameter monitoring system if you vent 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 your catalytic cracking unit isn't subject to the NSPS for CO, you don't have to install and operate a continuous emission monitoring system or a continuous parameter monitoring system if you vent emissions to a boiler or process heater in which all vent streams are introduced into the flame zone.

(2) Conduct each performance test for a catalytic cracking unit not subject to the NSPS for CO according to the requirements in §63.1571 and under the conditions specified in Table 11 of this subpart.

(3) Establish each site-specific operating limit in Table 9 of this subpart that applies to you according to the procedures in Table 11 of this subpart.

(4) Demonstrate initial compliance with each emission limitation that applies to you according to Table 12 of this subpart.

(5) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status according to §63.1574.

(6) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 8 and 9 of this subpart that applies to you according to the methods specified in Tables 13 and 14 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

[67 FR 17773, Apr. 1, 2002, as amended at 80 FR 75275, Dec. 1, 2015; 81 FR 45243, July 13, 2016]

§63.1566 What are my requirements for organic HAP emissions from catalytic reforming units?

(a) What emission limitations and work practice standards must I meet? You must:

(1) Meet each emission limitation in Table 15 of this subpart that applies to you. You can choose from the two options in paragraphs (a)(1)(i) and (ii) of this section.

(i) You can elect to vent emissions of total organic compounds (TOC) to a flare (Option 1). On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare must meet the control device requirements in §63.11(b) or the requirements of §63.670.

(ii) You can elect to meet a TOC or nonmethane TOC percent reduction standard or concentration limit, whichever is less stringent (Option 2).

(2) Comply with each site-specific operating limit in Table 16 of this subpart that applies to you.

(3) Except as provided in paragraph (a)(4) of this section, the emission limitations in Tables 15 and 16 of this subpart apply to emissions from catalytic reforming unit process vents associated with initial catalyst depressuring and catalyst purging operations that occur prior to the coke burn-off cycle. The emission limitations in Tables 15 and 16 of this subpart do not apply to the coke burn-off, catalyst rejuvenation, reduction or activation vents, or to the control systems used for these vents.

(4) The emission limitations in tables 15 and 16 of this subpart do not apply to emissions from process vents during passive depressuring when the reactor vent pressure is 5 pounds per square inch gauge (psig) or less or during active depressuring or purging prior to January 30, 2019, when the reactor vent pressure is 5 psig or less. On and after January 30, 2019, the emission limitations in tables 15 and 16 of this subpart do apply to emissions from process vents during active purging operations (when nitrogen or other purge gas is actively introduced to the reactor vessel) or active depressuring (using a vacuum pump, ejector system, or similar device) regardless of the reactor vent pressure.

(5) 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) How do I demonstrate initial compliance with the emission limitations and work practice standard? You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in §63.1572 and Table 17 of this subpart.

(2) Conduct each performance test for a catalytic reforming unit according to the requirements in §63.1571 and under the conditions specified in Table 18 of this subpart.

(3) Establish each site-specific operating limit in Table 16 of this subpart that applies to you according to the procedures in Table 18 of this subpart.

(4) Use the procedures in paragraph (b)(4)(i) or (ii) of this section to determine initial compliance with the emission limitations.

(i) If you elect the percent reduction standard under Option 2, calculate the emission rate of nonmethane TOC using Equation 1 of this section (if you use Method 25) or Equation 2 of this section (if you use Method 25A or Methods 25A and 18), then calculate the mass emission reduction using Equation 3 of this section as follows:

$$E = K_4 M_c Q_s \qquad (Eq.\ 1)$$

Where:

E = Emission rate of nonmethane TOC in the vent stream, kilograms-C per hour;

K_4 = Constant, 6.0×10^{-5} (kilograms per milligram)(minutes per hour);

M_c = Mass concentration of total gaseous nonmethane organic (as carbon) as measured and calculated using Method 25 in appendix A to part 60 of this chapter, mg/dscm; and

Q_s = Vent stream flow rate, dscm/min, at a temperature of 20 degrees Celsius (C).

$$E = K_5 \left(C_{TOC} - \tfrac{1}{6} C_{methane} \right) Q_s \qquad (Eq.\ 2)$$

Where:

K_5 = Constant, 1.8×10^{-4} (parts per million)$^{-1}$ (gram-mole per standard cubic meter) (gram-C per gram-mole-hexane) (kilogram per gram) (minutes per hour), where the standard temperature (standard cubic meter) is at 20 degrees C (uses 72g-C/g.mole hexane);

C_{TOC} = Concentration of TOC on a dry basis in ppmv as hexane as measured by Method 25A in appendix A to part 60 of this chapter;

$C_{methane}$ = Concentration of methane on a dry basis in ppmv as measured by Method 18 in appendix A to part 60 of this chapter. If the concentration of methane is not determined, assume $C_{methane}$ equals zero; and

Q_s = Vent stream flow rate, dry standard cubic meters per minute, at a temperature of 20 degrees C.

$$\% \text{ reduction} = \frac{E_i - E_o}{E_i} \times 100\% \qquad (Eq. 3)$$

Where:

E_i = Mass emission rate of TOC at control device inlet, kg/hr; and

E_o = Mass emission rate of TOC at control device outlet, kg/hr.

(ii) If you elect the 20 parts per million by volume (ppmv) concentration limit, correct the measured TOC concentration for oxygen (O_2) content in the gas stream using Equation 4 of this section as follows:

$$C_{NMTOC,3\%O_2} = \left(C_{TOC} - \tfrac{1}{6} C_{methane}\right)\left(\frac{17.9\%}{20.9\% - \%O_2}\right) \qquad (Eq. 4)$$

Where:

$C_{NMTOC,\,3\%O2}$ = Concentration of nonmethane TOC on a dry basis in ppmv as hexane corrected to 3 percent oxygen.

(5) You are not required to do a TOC performance test if:

(i) You elect to vent emissions to a flare as provided in paragraph (a)(1)(i) of this section (Option 1); or

(ii) You elect the TOC percent reduction or concentration limit in paragraph (a)(1)(ii) of this section (Option 2), and you use 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.

(6) Demonstrate initial compliance with each emission limitation that applies to you according to Table 19 of this subpart.

(7) Demonstrate initial compliance with the work practice standard in paragraph (a)(5) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(8) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 15 and 16 of this subpart that applies to you according to the methods specified in Tables 20 and 21 of this subpart.

(2) Demonstrate continuous compliance with the work practice standards in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6938, Feb. 9, 2005; 80 FR 75275, Dec. 1, 2015; 81 FR 45243, July 13, 2016]

§63.1567 What are my requirements for inorganic HAP emissions from catalytic reforming units?

(a) What emission limitations and work practice standards must I meet? You must:

(1) Meet each emission limitation in Table 22 to this subpart that applies to you. If you operate a catalytic reforming unit in which different reactors in the catalytic reforming unit are regenerated in separate regeneration systems, then these emission limitations apply to each separate regeneration system. These emission limitations apply to emissions from catalytic reforming unit process vents associated with the coke burn-off and catalyst rejuvenation operations during coke burn-off and catalyst regeneration. You can choose from the two options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to meet a percent reduction standard for hydrogen chloride (HCl) emissions (Option 1); or

(ii) You can elect to meet an HCl concentration limit (Option 2).

(2) Meet each site-specific operating limit in Table 23 of this subpart that applies to you. These operating limits apply during coke burn-off and catalyst rejuvenation.

(3) 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) How do I demonstrate initial compliance with the emission limitations and work practice standard? You must:

(1) Install, operate, and maintain a continuous monitoring system(s) according to the requirements in §63.1572 and Table 24 of this subpart.

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

(3) Establish each site-specific operating limit in Table 23 of this subpart that applies to you according to the procedures in Table 25 of this subpart.

(4) Use the equations in paragraphs (b)(4)(i) through (iv) of this section to determine initial compliance with the emission limitations.

(i) Correct the measured HCl concentration for oxygen (O_2) content in the gas stream using Equation 1 of this section as follows:

$$C_{HCl,3\%O_2} = \left(\frac{17.9\%}{20.9\% - \%O_2} \right) C_{HCl} \qquad \text{(Eq. 1)}$$

Where:

$C_{HCl,3\%}O_2$ = Concentration of HCl on a dry basis in ppmv corrected to 3 percent oxygen or 1 ppmv, whichever is greater;

C_{HCl} = Concentration of HCl on a dry basis in ppmv, as measured by Method 26A in 40 CFR part 60, appendix A; and

$\%O_2$ = Oxygen concentration in percent by volume (dry basis).

(ii) If you elect the percent reduction standard, calculate the emission rate of HCl using Equation 2 of this section; then calculate the mass emission reduction from the mass emission rates using Equation 3 of this section as follows:

$$E_{HCl} = K_6 C_{HCl} Q_s \qquad \text{(Eq. 2)}$$

Where:

E_{HCl} = Emission rate of HCl in the vent stream, grams per hour;

K_6 = Constant, 0.091 (parts per million)$^{-1}$ (grams HCl per standard cubic meter) (minutes per hour), where the standard temperature (standard cubic meter) is at 20 degrees Celsius (C); and

Q_s = Vent stream flow rate, dscm/min, at a temperature of 20 degrees C.

$$\text{HCl\%reduction} = \frac{E_{HCl,i} - E_{HCl,o}}{E_{HCl,i}} \times 100\% \qquad \text{(Eq. 3)}$$

Where:

$E_{HCl,i}$ = Mass emission rate of HCl at control device inlet, g/hr; and

$E_{HCl,o}$ = Mass emission rate of HCl at control device outlet, g/hr.

(iii) If you are required to use a colormetric tube sampling system to demonstrate continuous compliance with the HCl concentration operating limit, calculate the HCl operating limit using Equation 4 of this section as follows:

$$C_{HCl,ppmvLimit} = 0.9 C_{HCl,AveTube} \left(\frac{C_{HCl,RegLimit}}{C_{HCl,3\%O_2}} \right) \qquad \text{(Eq. 4)}$$

Where:

$C_{HCl,ppmvLimit}$ = Maximum permissible HCl concentration for the HCl concentration operating limit, ppmv;

$C_{HCl,AveTube}$ = Average HCl concentration from the colormetric tube sampling system, calculated as the arithmetic average of the average HCl concentration measured for each performance test run, ppmv or 1 ppmv, whichever is greater; and

$C_{HCl,RegLimit}$ = Maximum permissible outlet HCl concentration for the applicable catalytic reforming unit as listed in Table 22 of this subpart, either 10 or 30 ppmv.

(iv) If you are required to use a colormetric tube sampling system to demonstrate continuous compliance with the percent reduction operating limit, calculate the HCl operating limit using Equation 5 of this section as follows:

$$C_{HCl,\%Limit} = 0.9 C_{HCl,AveTube} \left(\frac{100 - \%\text{HClReduction}_{Limit}}{100 - \%\text{HClReduction}_{Test}} \right) \qquad \text{(Eq. 5)}$$

Where:

$C_{HCl,\%Limit}$ = Maximum permissible HCl concentration for the percent reduction operating limit, ppmv;

$\%HCl\ Reduction_{Limit}$ = Minimum permissible HCl reduction for the applicable catalytic reforming unit as listed in Table 22 of this subpart, either 97 or 92 percent; and

$\%HCl\ Reduction_{Test}$ = Average percent HCl reduction calculated as the arithmetic average HCl reduction calculated using Equation 3 of this section for each performance source test, percent.

(5) Demonstrate initial compliance with each emission limitation that applies to you according to Table 26 of this subpart.

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your Notification of Compliance Status.

(7) Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.1574.

(c) How do I demonstrate continuous compliance with the emission limitations and work practice standard? You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 22 and 23 of this subpart that applies to you according to the methods specified in Tables 27 and 28 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by maintaining records to document conformance with the procedures in your operation, maintenance and monitoring plan.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6939, Feb. 9, 2005]

§63.1568 What are my requirements for HAP emissions from sulfur recovery units?

(a) What emission limitations and work practice standard must I meet? You must:

(1) Meet each emission limitation in Table 29 of this subpart that applies to you. If your sulfur recovery unit is subject to the NSPS for sulfur oxides in §60.104 or §60.102a(f)(1) of this chapter, you must meet the emission limitations for NSPS units. If your sulfur recovery unit is not subject to one of these NSPS for sulfur oxides, you can choose from the options in paragraphs (a)(1)(i) through (ii) of this section:

(i) You can elect to meet the NSPS requirements in §60.104(a)(2) or §60.102a(f)(1) of this chapter (Option 1); or

(ii) You can elect to meet the total reduced sulfur (TRS) emission limitation (Option 2).

(2) Meet each operating limit in Table 30 of this subpart that applies to you.

(3) 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.

(4) On or before the date specified in §63.1563(d), you must comply with one of the three options in paragraphs (a)(4)(i) through (iii) of this section during periods of startup and shutdown.

(i) You can elect to comply with the requirements in paragraphs (a)(1) and (2) of this section.

(ii) You can elect to send any startup or shutdown purge gases to a flare. On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare must meet the design and operating requirements in §63.11(b) or the requirements of §63.670.

(iii) You can elect to send any startup or shutdown purge gases to a thermal oxidizer or incinerator operated at a minimum hourly average temperature of 1,200 degrees Fahrenheit in the firebox and a minimum hourly average outlet oxygen (O_2) concentration of 2 volume percent (dry basis).

(b) How do I demonstrate initial compliance with the emission limitations and work practice standards? You must:

(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 to you according to the procedures in Table 32 of this subpart.

(4) Correct the reduced sulfur samples to zero percent excess air using Equation 1 of this section as follows:

$$C_{adj} = C_{meas}\left[20.9_c/(20.9-\%O_2)\right] \qquad (Eq.\ 1)$$

Where:

C_{adj} = pollutant concentration adjusted to zero percent oxygen, ppm or g/dscm;

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm;

20.9_c = 20.9 percent oxygen—0.0 percent oxygen (defined oxygen correction basis), percent;

20.9 = oxygen concentration in air, percent;

$\%O_2$ = oxygen concentration measured on a dry basis, percent.

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

(6) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your notification of compliance status.

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

(c) How do I demonstrate continuous compliance with the emission limitations and work practice standards? You must:

(1) Demonstrate continuous compliance with each emission limitation in Tables 29 and 30 of this subpart that applies to you according to the methods specified in Tables 34 and 35 of this subpart.

(2) Demonstrate continuous compliance with the work practice standard in paragraph (a)(3) of this section by complying with the procedures in your operation, maintenance, and monitoring plan.

[67 FR 17773, Apr. 11, 2002, as amended at 80 FR 75275, Dec. 1, 2015; 81 FR 45244, July 13, 2016]

§63.1569 What are my requirements for HAP emissions from bypass lines?

(a) What work practice standards must I meet? (1) You must meet each work practice standard in Table 36 of this subpart that applies to you. You can choose from the four options in paragraphs (a)(1)(i) through (iv) of this section:

(i) You can elect to install an automated system (Option 1);

(ii) You can elect to use a manual lock system (Option 2);

(iii) You can elect to seal the line (Option 3); or

(iv) You can elect to vent to a control device (Option 4).

(2) As provided in §63.6(g), we, the EPA, may choose to grant you permission to use an alternative to the work practice standard in paragraph (a)(1) of this section.

(3) You 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) How do I demonstrate initial compliance with the work practice standards? You must:

(1) If you elect the option in paragraph (a)(1)(i) of this section, 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 to you according to Table 38 of this subpart.

(3) Demonstrate initial compliance with the work practice standard in paragraph (a)(3) of this section by submitting the operation, maintenance, and monitoring plan to your permitting authority as part of your notification of compliance status.

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

(c) How do I demonstrate continuous compliance with the work practice standards? You must:

(1) Demonstrate continuous compliance with each work practice standard in Table 36 of this subpart that applies to you according to the requirements in Table 39 of this subpart.

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

General Compliance Requirements

§63.1570 What are my general requirements for complying with this subpart?

(a) You must be in compliance with all of the non-opacity standards in this subpart at all times.

(b) You must be in compliance with the opacity and visible emission limits in this subpart at all times.

(c) At all times, you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(d) During the period between the compliance date specified for your affected source and the date upon which continuous monitoring systems have been installed and validated and any applicable operating limits have been set, you must maintain a log that documents the procedures used to minimize emissions from process and emissions control equipment according to the general duty in paragraph (c) of this section.

(e) [Reserved]

(f) You must report each instance in which you did not meet each emission limitation and each operating limit in this subpart that applies to you. This includes periods of startup, shutdown, and malfunction. You also must report each instance in which you did not meet the work practice standards in this subpart that apply to you. 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 §63.1575.

[67 FR 17773, Apr. 11, 2002, as amended at 71 FR 20462, Apr. 20, 2006; 80 FR 75276, Dec. 1, 2015]

§63.1571 How and when do I conduct a performance test or other initial compliance demonstration?

(a) *When must I conduct a performance test?* You must conduct performance tests and report the results by no later than 150 days after the compliance date specified for your source in §63.1563 and according to the provisions in §63.7(a)(2). If you are required to do a performance evaluation or test for a semi-regenerative catalytic reforming unit catalyst regenerator vent, you may do them at the first regeneration cycle after your compliance date and report the results in a followup 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, you must conduct the initial compliance demonstration within 30 calendar days after the compliance date that is specified for your source in §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 your source in §63.1563 and ends at 11:59 p.m., 30 calendar days after the compliance date that is specified for your source in §63.1563.

(3) If you commenced construction or reconstruction between September 11, 1998 and April 11, 2002, you must demonstrate initial compliance with either the proposed emission limitation or the promulgated emission limitation no later than October 8, 2002 or within 180 calendar days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(4) If you commenced construction or reconstruction between September 11, 1998 and April 11, 2002, and you chose to comply with the proposed emission limitation when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limitation by October 10, 2005, or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(5) *Periodic performance testing for PM or Ni.* Except as provided in paragraphs (a)(5)(i) and (ii) of this section, conduct a periodic performance test for PM or Ni for each catalytic cracking unit at least once every 5 years according to the requirements in Table 4 of this subpart. You must conduct the first periodic performance test no later than August 1, 2017.

(i) Catalytic cracking units monitoring PM concentration with a PM CEMS are not required to conduct a periodic PM performance test.

(ii) Conduct a performance test annually if you comply with the emission limits in Item 1 (NSPS subpart J) or Item 4 (Option 1a) in Table 1 of this subpart and the PM emissions measured during the most recent performance source test are greater than 0.80 g/kg coke burn-off.

(6) *One-time performance testing for HCN.* Conduct a performance test for HCN from each catalytic cracking unit no later than August 1, 2017 according to the applicable requirements in paragraphs (a)(6)(i) and (ii) of this section.

(i) If you conducted a performance test for HCN for a specific catalytic cracking unit between March 31, 2011 and February 1, 2016, you may submit a request to the Administrator to use the previously conducted performance test results to fulfill the one-time performance test requirement for HCN for each of the catalytic cracking units tested according to the requirements in paragraphs (a)(6)(i)(A) through (D) of this section.

(A) The request must include a copy of the complete source test report, the date(s) of the performance test and the test methods used. If available, you must also indicate whether the catalytic cracking unit catalyst regenerator was operated in partial or complete combustion mode during the test, the control device configuration, including whether platinum or palladium combustion promoters were used during the test, and the CO concentration (measured using CO CEMS or manual test method) for each test run.

(B) You must submit a separate request for each catalytic cracking unit tested and you must submit each request to the Administrator no later than March 30, 2016.

(C) The Administrator will evaluate each request with respect to the completeness of the request, the completeness of the submitted test report and the appropriateness of the test methods used. The Administrator will notify the facility within 60 days of receipt of the request if it is approved or denied. If the Administrator fails to respond to the facility within 60 days of receipt of the request, the request will be automatically approved.

(D) If the request is approved, you do not need to conduct an additional HCN performance test. If the request is denied, you must conduct an additional HCN performance test following the requirements in (a)(6)(ii) of this section.

(ii) Unless you receive approval to use a previously conducted performance test to fulfill the one-time performance test requirement for HCN for your catalytic cracking unit as provided in paragraph (a)(6)(i) of this section, conduct a performance test for HCN for each catalytic cracking unit no later than August 1, 2017 according to following requirements:

(A) Select sampling port location, determine volumetric flow rate, conduct gas molecular weight analysis and measure moisture content as specified in either Item 1 of Table 4 of this subpart or Item 1 of Table 11 of this subpart.

(B) Measure HCN concentration using Method 320 of appendix A of this part. The method ASTM D6348-03 (Reapproved 2010) including Annexes A1 through A8 (incorporated by reference—see §63.14) is an acceptable alternative to EPA Method 320 of appendix A of this part. The method ASTM D6348-12e1 (incorporated by reference—see §63.14) is an acceptable alternative to EPA Method 320 of appendix A of this part with the following two caveats:

(*1*) The test plan preparation and implementation in the Annexes to ASTM D6348-03 (Reapproved 2010), Sections A1 through A8 are mandatory; and

(*2*) In ASTM D6348-03 (Reapproved 2010) Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5). In order for the test data to be acceptable for a compound, %R must be 70% ≥ R ≤ 130%. If the %R value does not meet this criterion for a target compound, the test data is not acceptable for that compound and the test must be repeated for that analyte (*i.e.,* the sampling and/or analytical procedure should be adjusted before a retest). The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound by using the following equation:

Reported Result = (Measured Concentration in the Stack × 100÷/% R.

(C) Measure CO concentration as specified in either Item 2 or 3a of Table 11 of this subpart.

(D) Record and include in the test report an indication of whether the catalytic cracking unit catalyst regenerator was operated in partial or complete combustion mode and the control device configuration, including whether platinum or palladium combustion promoters were used during the test.

(b) *What are the general requirements for performance test and performance evaluations?* You must:

(1) Performance tests shall be conducted according to the provisions of §63.7(e) except that performance tests shall be conducted at maximum representative operating capacity for the process. During the performance test, you must operate the control device at either maximum or minimum representative operating conditions for monitored control device parameters, whichever results in lower emission reduction. You must not conduct a performance test during startup, shutdown, periods when the control device is bypassed or periods when the process, monitoring equipment or control device is not operating properly. You may not conduct performance tests during periods of malfunction. You must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that the test was conducted at maximum representative operating capacity. Upon request, you must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

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

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

(4) 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 §63.1564, and determining the arithmetic average of the calculated emission rates.

(c) *What procedures must I use for an engineering assessment?* You 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 you use an engineering assessment, you must document all data, assumptions, and procedures to the satisfaction of the applicable permitting authority. An engineering assessment may include the approaches listed in paragraphs (c)(1) through (c)(4) of this section. Other engineering assessments may be used but are subject to review and approval by the applicable permitting authority.

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

(3) You 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) You 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) *Can I adjust the process or control device measured values when establishing an operating limit?* If you do a performance test to demonstrate compliance, you must base the process or control device operating limits for continuous parameter monitoring systems on the results measured during the performance test. You may adjust the values measured during the performance test according to the criteria in paragraphs (d)(1) through (3) of this section.

(1) If you must meet the HAP metal emission limitations in §63.1564, you elect the option in paragraph (a)(1)(iii) in §63.1564 (Ni lb/hr), and you use continuous parameter monitoring systems, you must establish an operating limit for the equilibrium catalyst Ni concentration based on the laboratory analysis of the equilibrium catalyst Ni concentration

from the initial performance test. Section 63.1564(b)(2) allows you to adjust the laboratory measurements of the equilibrium catalyst Ni concentration to the maximum level. You must make this adjustment using Equation 1 of this section as follows:

$$Ecat\text{-Limit} = \frac{13 \text{ g Ni/hr}}{NiEmR1_{st}} \times Ecat_{st} \qquad (Eq.\ 1)$$

Where:

Ecat-Limit = Operating limit for equilibrium catalyst Ni concentration, mg/kg;

$NiEmR1_{st}$ = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 5 of this section for each performance test run, g Ni/hr; and

$Ecat_{st}$ = Average equilibrium Ni concentration from laboratory test results, mg/kg.

(2) If you must meet the HAP metal emission limitations in §63.1564, you elect the option in paragraph (a)(1)(iv) in §63.1564 (Ni per coke burn-off), and you use continuous parameter monitoring systems, you must establish an operating limit for the equilibrium catalyst Ni concentration based on the laboratory analysis of the equilibrium catalyst Ni concentration from the initial performance test. Section 63.1564(b)(2) allows you to adjust the laboratory measurements of the equilibrium catalyst Ni concentration to the maximum level. You must make this adjustment using Equation 2 of this section as follows:

$$Ecat\text{-Limit} = \frac{1.0 \text{ mg/kg coke burn-off}}{NiEmR2_{st}} \times Ecat_{st} \qquad (Eq.\ 2)$$

Where:

$NiEmR2_{st}$ = Average Ni emission rate calculated as the arithmetic average Ni emission rate using Equation 8 of §63.1564 for each performance test run, mg/kg coke burn-off.

(3) If you choose to adjust the equilibrium catalyst Ni concentration to the maximum level, you can't adjust any other monitored operating parameter (i.e., gas flow rate, voltage, pressure drop, liquid-to-gas ratio).

(4) Except as specified in paragraph (d)(3) of this section, if you use continuous parameter monitoring systems, you may adjust one of your monitored operating parameters (flow rate, total power and secondary current, pressure drop, liquid-to-gas ratio) from the average of measured values during the performance test to the maximum value (or minimum value, if applicable) representative of worst-case operating conditions, if necessary. This adjustment of measured values may be done using control device design specifications, manufacturer recommendations, or other applicable information. You must provide supporting documentation and rationale in your Notification of Compliance Status, demonstrating to the satisfaction of your permitting authority, that your affected source complies with the applicable emission limit at the operating limit based on adjusted values.

(e) *Can I change my operating limit?* You may change the established operating limit by meeting the requirements in paragraphs (e)(1) through (3) of this section.

(1) You may change your established operating limit for a continuous parameter monitoring system by doing an additional performance test, a performance test in conjunction with an engineering assessment, or an engineering assessment to verify that, at the new operating limit, you are in compliance with the applicable emission limitation.

(2) You must establish a revised operating limit for your continuous parameter monitoring system if you make any change in process or operating conditions that could affect control system performance or you change designated conditions after the last performance or compliance tests were done. You can establish the revised operating limit as described in paragraph (e)(1) of this section.

(3) You may change your site-specific opacity operating limit or Ni operating limit only by doing a new performance test.

[67 FR 17773, Apr. 11, 2002, as amended at 80 FR 75276, Dec. 1, 2015]

§63.1572 What are my monitoring installation, operation, and maintenance requirements?

(a) You must install, operate, and maintain each continuous emission monitoring system according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) You must install, operate, and maintain each continuous emission monitoring system according to the requirements in Table 40 of this subpart.

(2) If you use a continuous emission monitoring system to meet the NSPS CO or SO_2 limit, you must conduct a performance evaluation of each continuous emission monitoring system according to the requirements in §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 §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 §63.8(g)(2).

(b) You must install, operate, and maintain each continuous opacity monitoring system according to the requirements in paragraphs (b)(1) through (3) of this section.

(1) Each continuous opacity monitoring system must be installed, operated, and maintained according to the requirements in Table 40 of this subpart.

(2) If you use a continuous opacity monitoring system to meet the NSPS opacity limit, you must conduct a performance evaluation of each continuous opacity monitoring system according to the requirements in §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 §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) Except for flare monitoring systems, you must install, operate, and maintain each continuous parameter monitoring system according to the requirements in paragraphs (c)(1) through (5) of this section. For flares, on and after January 30, 2019, you must install, operate, calibrate, and maintain monitoring systems as specified in §§63.670 and 63.671. Prior to January 30, 2019, you must either meet the monitoring system requirements in paragraphs (c)(1) through (5) of this section or meet the requirements in §§63.670 and 63.671.

(1) You must install, operate, and maintain each continuous parameter monitoring system according to the requirements in Table 41 of this subpart. You must also meet the equipment specifications in Table 41 of this subpart if pH strips or colormetric tube sampling systems are used. You must install, operate, and maintain each continuous parameter monitoring system according to the requirements in Table 41 of this subpart. You must meet the requirements in Table 41 of this subpart for BLD systems. Alternatively, before August 1, 2017, you may install, operate, and maintain each continuous parameter monitoring system 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. You must 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, except for BLD systems.

(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, except for BLD systems. 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, except for BLD systems.

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

(d) You must monitor and collect data according to the requirements in paragraphs (d)(1) and (2) of this section.

(1) You must conduct all monitoring in continuous operation (or collect data at all required intervals) at all times the affected source is operating.

(2) You may not use data recorded during required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments) for purposes of this regulation, including data averages and calculations, for fulfilling a minimum data availability requirement, if applicable. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6940, Feb. 9, 2005; 80 FR 75277, Dec. 1, 2015]

§63.1573 What are my monitoring alternatives?

(a) *What are the approved alternatives for measuring gas flow rate?* (1) You may use this alternative to a continuous parameter monitoring system for the catalytic regenerator exhaust gas flow rate for your catalytic cracking unit if the unit does not introduce any other gas streams into the catalyst regeneration vent (i.e., complete combustion units with no additional combustion devices). You may also use this alternative to a continuous parameter monitoring system for the catalytic regenerator atmospheric exhaust gas flow rate for your catalytic reforming unit during the coke burn and rejuvenation cycles if the unit operates as a constant pressure system during these cycles. If you use this alternative, you shall use the same procedure for the performance test and for monitoring after the performance test. You shall:

(i) Install and operate a continuous parameter monitoring system to measure and record the hourly average volumetric air flow rate to the catalytic cracking unit or catalytic reforming unit regenerator. Or, you may determine and record the hourly average volumetric air flow rate to the catalytic cracking unit or catalytic reforming unit regenerator using the appropriate control room instrumentation.

(ii) Install and operate a continuous parameter monitoring system to measure and record the temperature of the gases entering the control device (or exiting the catalyst regenerator if you do not use an add-on control device).

(iii) Calculate and record the hourly average actual exhaust gas flow rate using Equation 1 of this section as follows:

$$Q_{gas} = (1.12\,scfm/dscfm) \times (Q_{air} + Q_{other}) \times \left(\frac{Temp_{gas}}{293^\circ K}\right) \times \left(\frac{1atm.}{P_{vent}}\right) \qquad \text{(Eq. 1)}$$

Where

Q_{gas} = Hourly average actual gas flow rate, acfm;

1.12 = Default correction factor to convert gas flow from dry standard cubic feet per minute (dscfm) to standard cubic feet per minute (scfm);

Q_{air} = Volumetric flow rate of air to regenerator, as determined from the control room instrumentations, dscfm;

Q_{other} = Volumetric flow rate of other gases entering the regenerator as determined from the control room instrumentations, dscfm. (Examples of “other” gases include an oxygen-enriched air stream to catalytic cracking unit regenerators and a nitrogen stream to catalytic reforming unit regenerators.);

$Temp_{gas}$ = Temperature of gas stream in vent measured as near as practical to the control device or opacity monitor, °K. For wet scrubbers, temperature of gas prior to the wet scrubber; and

P_{vent} = Absolute pressure in the vent measured as near as practical to the control device or opacity monitor, as applicable, atm. When used to assess the gas flow rate in the final atmospheric vent stack, you can assume P_{vent} = 1 atm.

(2) You may use this alternative to calculating Q_r, the volumetric flow rate of exhaust gas for the catalytic cracking regenerator as required in Equation 1 of §63.1564, if you have a gas analyzer installed in the catalytic cracking regenerator exhaust vent prior to the addition of air or other gas streams. You may measure upstream or downstream of an electrostatic precipitator, but you shall measure upstream of a carbon monoxide boiler. You shall:

(i) Install and operate a continuous parameter monitoring system to measure and record the hourly average volumetric air flow rate to the catalytic cracking unit regenerator. Or, you can determine and record the hourly average volumetric air flow rate to the catalytic cracking unit regenerator using the catalytic cracking unit control room instrumentation.

(ii) Install and operate a continuous gas analyzer to measure and record the concentration of carbon dioxide, carbon monoxide, and oxygen of the catalytic cracking regenerator exhaust.

(iii) Calculate and record the hourly average flow rate using Equation 2 of this section as follows:

$$Q_r = \frac{79 \times Q_{air} + \left(100 - \%O_{xy}\right) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. 2)}$$

Where:

Q_r = Volumetric flow rate of exhaust gas from the catalyst regenerator before adding air or gas streams, dscm/min (dscf/min);

79 = Default concentration of nitrogen and argon in dry air, percent by volume (dry basis);

$\%O_{xy}$ = Oxygen concentration in oxygen-enriched air stream, percent by volume (dry basis);

Q_{oxy} = Volumetric flow rate of oxygen-enriched air stream to regenerator as determined from the catalytic cracking unit control room instrumentations, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide concentration in regenerator exhaust, percent by volume (dry basis);

CO = Carbon monoxide concentration in regenerator exhaust, percent by volume (dry basis); and

$\%O_2$ = Oxygen concentration in regenerator exhaust, percent by volume (dry basis).

(b) *What is the approved alternative for monitoring pressure drop?* You may use this alternative to a continuous parameter monitoring system for pressure drop if you operate a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles. You shall:

(1) Conduct a daily check of the air or water pressure to the spray nozzles;

(2) Maintain records of the results of each daily check; and

(3) Repair or replace faulty (*e.g.,* leaking or plugged) air or water lines within 12 hours of identification of an abnormal pressure reading.

(c) *What is the approved alternative for monitoring pH or alkalinity levels?* You may use the alternative in paragraph (c)(1) or (2) of this section for a catalytic reforming unit.

(1) You shall measure and record the pH of the water (or scrubbing liquid) exiting the wet scrubber or internal scrubbing system at least once an hour during coke burn-off and catalyst rejuvenation using pH strips as an alternative to a continuous parameter monitoring system. The pH strips must meet the requirements in Table 41 of this subpart.

(2) You shall measure and record the alkalinity of the water (or scrubbing liquid) exiting the wet scrubber or internal scrubbing system at least once an hour during coke burn-off and catalyst rejuvenation using titration as an alternative to a continuous parameter monitoring system.

(d) *Can I use another type of monitoring system?* You may use an automated data compression system. An automated data compression system does not record monitored operating parameter values at a set frequency (*e.g.,* once every hour) but records all values that meet set criteria for variation from previously recorded values. You must maintain a record of the description of the monitoring system and data 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 of the criteria in paragraphs (d)(1) through (5) of this section:

(1) The system measures the operating parameter value at least once every hour;

(2) The system records at least 24 values each day during periods of operation;

(3) The system records the date and time when monitors are turned off or on;

(4) The system recognizes unchanging data that may indicate the monitor is not functioning properly, alerts the operator, and records the incident; and

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

(e) *Can I monitor other process or control device operating parameters?* You may request approval to monitor parameters other than those required in this subpart. You must request approval if:

(1) You use a control device other than a thermal incinerator, boiler, process heater, flare, electrostatic precipitator, or wet scrubber;

(2) You use a combustion control device (e.g., incinerator, flare, boiler or process heater with a design heat capacity of at least 44 MW, boiler or process heater where the vent stream is introduced into the flame zone), electrostatic precipitator, or scrubber but want to monitor a parameter other than those specified; or

(3) You wish to use another type of continuous emission monitoring system that provides direct measurement of a pollutant (i.e., a PM or multi-metals HAP continuous emission monitoring system, a carbonyl sulfide/carbon disulfide continuous emission monitoring system, a TOC continuous emission monitoring system, or HCl continuous emission monitoring system).

(f) *How do I request to monitor alternative parameters?* You must submit a request for review and approval or disapproval to the Administrator. The request must include the information in paragraphs (f)(1) through (5) of this section.

(1) A description of each affected source and the parameter(s) to be monitored to determine whether the affected source will continuously comply with the emission limitations and an explanation of the criteria used to select the parameter(s).

(2) A description of the methods and procedures that will be used to demonstrate that the parameter can be used to determine whether the affected source will continuously comply with the emission limitations and the schedule for this demonstration. You must certify that you will establish an operating limit for the monitored parameter(s) that represents the conditions in existence when the control device is being properly operated and maintained to meet the emission limitation.

(3) The frequency and content of monitoring, recording, and reporting, if monitoring and recording are not continuous. You also must include the rationale for the proposed monitoring, recording, and reporting requirements.

(4) Supporting calculations.

(5) Averaging time for the alternative operating parameter.

(g) *How do I apply for alternative monitoring requirements if my catalytic cracking unit is equipped with a wet scrubber and I have approved alternative monitoring requirements under the new source performance standards for petroleum refineries?* (1) You may request alternative monitoring requirements according to the procedures in this paragraph if you meet each of the conditions in paragraphs (g)(1)(i) through (iii) of this section:

(i) Your fluid catalytic cracking unit regenerator vent is subject to the PM limit in 40 CFR 60.102(a)(1) and uses a wet scrubber for PM emissions control;

(ii) You have alternative monitoring requirements for the continuous opacity monitoring system requirement in 40 CFR 60.105(a)(1) approved by the Administrator; and

(iii) You are required by this subpart to install, operate, and maintain a continuous opacity monitoring system for the same catalytic cracking unit regenerator vent for which you have approved alternative monitoring requirements.

(2) You can request approval to use an alternative monitoring method prior to submitting your notification of compliance status, in your notification of compliance status, or at any time.

(3) You must submit a copy of the approved alternative monitoring requirements along with a monitoring plan that includes a description of the continuous monitoring system or method, including appropriate operating parameters that will be monitored, test results demonstrating compliance with the opacity limit used to establish an enforceable operating limit(s), and the frequency of measuring and recording to establish continuous compliance. If applicable, you must also include operation and maintenance requirements for the continuous monitoring system.

(4) We will contact you within 30 days of receipt of your application to inform you of approval or of our intent to disapprove your request.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6940, Feb. 9, 2005; 80 FR 75277, Dec. 1, 2015]

Notifications, Reports, and Records

§63.1574 What notifications must I submit and when?

(a) Except as allowed in paragraphs (a)(1) through (3) of this section, you must submit all of the notifications in §§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) that apply to you by the dates specified.

(1) You must submit the notification of your intention to construct or reconstruct according to §63.9(b)(5) unless construction or reconstruction had commenced and initial startup had not occurred before April 11, 2002. In this case, you must submit the notification as soon as practicable before startup but no later than July 10, 2002. This deadline also applies to the application for approval of construction or reconstruction and approval of construction or reconstruction based on State preconstruction review required in §§63.5(d)(1)(i) and 63.5(f)(2).

(2) You must submit the notification of intent to conduct a performance test required in §63.7(b) at least 30 calendar days before the performance test is scheduled to begin (instead of 60 days).

(3) If you are required to conduct an initial performance test, performance evaluation, design evaluation, opacity observation, visible emission observation, or other initial compliance demonstration, you must submit a notification of compliance status according to §63.9(h)(2)(ii). You 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. In a State with an approved operating permit program where delegation of authority under section 112(l) of the CAA has not been requested or approved, you must provide a duplicate notification to the applicable Regional Administrator. If the required information has been submitted previously, you do not have to provide a separate notification of compliance status. Just 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, you 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, you must submit the notification of compliance status, including the performance test results, no later than 150 calendar days after the compliance date specified for your affected source in §63.1563.

(b) As specified in §63.9(b)(2), if you startup your new affected source before April 11, 2002, you must submit the initial notification no later than August 9, 2002.

(c) If you startup your new or reconstructed affected source on or after April 11, 2002, you must submit the initial notification no later than 120 days after you become subject to this subpart.

(d) You also must include the information in Table 42 of this subpart in your notification of compliance status.

(e) If you request an extension of compliance for an existing catalytic cracking unit as allowed in §63.1563(c), you must submit a notification to your permitting authority containing the required information by October 13, 2003.

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

(1) You must submit the plan to your permitting authority for review and approval along with your notification of compliance status. While you do not have to include the entire plan in your permit under part 70 or 71 of this chapter, you must include the duty to prepare and implement the plan as an applicable requirement in your part 70 or 71 operating permit. You must submit any changes to your permitting authority for review and approval and comply with the plan as submitted until the change is approved.

(2) Each plan must include, at a minimum, the information specified in paragraphs (f)(2)(i) through (xii) of this section.

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

(iv) Procedures and analytical methods you 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 you will use to determine the pH of the water (or scrubbing liquid) exiting a wet scrubber if you use pH strips.

(vi) Procedures you will use to determine the HCl concentration of gases from a catalytic reforming unit when you use a colormetric tube sampling system, including procedures for correcting for pressure (if applicable to the sampling equipment) and the sampling locations that will be used for compliance monitoring purposes.

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

(viii) Monitoring schedule, including when you will monitor and when you 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 you use to meet an emission limit in this subpart. This plan must include procedures you will use for calibrations, accuracy audits, and adjustments to the system needed to meet applicable requirements for the system.

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

(xi) If you use a fixed-bed gas-solid adsorption system to control emissions from a catalytic reforming unit, you must implement corrective action procedures if the HCl concentration measured at the selected compliance monitoring sampling location within the bed exceeds the operating limit. These procedures must require, at minimum, repeat measurement and recording of the HCl concentration in the adsorption system exhaust gases and at the selected compliance monitoring sampling location within the bed. If the HCl concentration at the selected compliance monitoring location within the bed is above the operating limit during the repeat measurement while the HCl concentration in the adsorption system exhaust gases remains below the operating limit, the adsorption bed must be replaced as soon as practicable. Your procedures must specify the sampling frequency that will be used to monitor the HCl concentration in the adsorption system exhaust gases subsequent to the repeat measurement and prior to replacement of the sorbent material (but not less frequent than once every 4 hours during coke burn-off). If the HCl concentration of the adsorption system exhaust gases is above the operating limit when measured at any time, the adsorption bed must be replaced within 24 hours or before the next regeneration cycle, whichever is longer.

(xii) Procedures that will be used for purging the catalyst if you do not use a control device to comply with the organic HAP emission limits for catalytic reforming units. These procedures will include, but are not limited to, specification of the minimum catalyst temperature and the minimum cumulative volume of gas per mass of catalyst used for purging prior to uncontrolled releases (i.e., during controlled purging events); the maximum purge gas temperature for uncontrolled purge events; and specification of the monitoring systems that will be used to monitor and record data during each purge event.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6941, Feb. 9, 2005; 80 FR 75278, Dec. 1, 2015]

§63.1575 What reports must I submit and when?

(a) You must submit each report in Table 43 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule, you must submit each report by the date in Table 43 of 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 §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 your affected source in §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 your affected source in §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 the permitting authority has established dates for submitting semiannual reports pursuant to §70.6(a)(3)(iii)(A) or §71.6(a)(3)(iii)(A) of this chapter, 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 (4) of this section.

(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 emission limitation that applies to you 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 you are 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 semiannual compliance report must contain the information in paragraphs (c)(1) through (3) of this section and the information in paragraphs (d)(1) through (4) of this section.

(1) The total operating time of each affected source during the reporting period and identification of the sources for which there was a deviation.

(2) Information on the number, date, time, duration, and cause of deviations (including unknown cause, if applicable).

(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).

(4) The applicable operating limit or work practice standard from which you deviated and either the parameter monitor reading during the deviation or a description of how you deviated from the work practice standard.

(e) For each deviation from an emission limitation occurring at an affected source where you are using a continuous opacity monitoring system or a continuous emission monitoring system to comply with the emission limitation, you must include the information in paragraphs (c)(1) through (3) of this section, in paragraphs (d)(1) through (3) of this section, and in paragraphs (e)(2) through (13) of this section.

(1) [Reserved]

(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 §63.8(c)(8).

(4) An estimate of the quantity of each regulated pollutant emitted over the emission limit during the deviation, and a description of the method used to estimate the emissions.

(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 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) You also must include the information required in paragraphs (f)(1) through (2) of this section in each compliance report, if applicable.

(1) You must include the information in paragraph (f)(1)(i) or (ii) of this section, if applicable.

(i) If you are complying with paragraph (k)(1) of this section, a summary of the results of any performance test done during the reporting period on any affected unit. Results of the performance test include the identification of the source tested, the date of the test, the percentage of emissions reduction or outlet pollutant concentration reduction (whichever is needed to determine compliance) for each run and for the average of all runs, and the values of the monitored operating parameters.

(ii) If you are not complying with paragraph (k)(1) of this section, a copy of any performance test done during the reporting period on any affected unit. The report may be included in the next semiannual compliance 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, you must 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.,* you want 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 your compliance report. You must include all information and data necessary to demonstrate compliance with the new emission standard selected and any other associated requirements.

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

(h) [Reserved]

(i) If the applicable permitting authority has approved a period of planned maintenance for your catalytic cracking unit according to the requirements in paragraph (j) of this section, you must include the following information in your compliance report.

(1) In the compliance report due for the 6-month period before the routine planned maintenance is to begin, you must include a full copy of your written request to the applicable permitting authority and written approval received from the applicable permitting authority.

(2) In the compliance report due after the routine planned maintenance is complete, you 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 you own or operate multiple catalytic cracking units that are served by a single wet scrubber emission control device (e.g., a Venturi scrubber), you may request the applicable permitting authority to approve a period of planned routine maintenance for the control device needed to meet requirements in your operation, maintenance, and monitoring plan. You must present data to the applicable permitting authority 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. The applicable permitting authority may require that you take specified actions to minimize emissions during the period of planned maintenance.

(1) You must submit a written request to the applicable permitting authority at least 6 months before the planned maintenance is scheduled to begin with a copy to the EPA Regional Administrator.

(2) Your written request must contain the information in paragraphs (j)(2)(i) through (v) of this section.

(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 you will take to minimize emissions during the period of planned maintenance.

(k) *Electronic submittal of performance test and CEMS performance evaluation data.* For performance tests or CEMS performance evaluations conducted on and after February 1, 2016, if required to submit the results of a performance test or CEMS performance evaluation, you must submit the results according to the procedures in paragraphs (k)(1) and (2) of this section.

(1) Within 60 days after the date of completing each performance test as required by this subpart, you must submit the results of the performance tests following the procedure specified in either paragraph (k)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic storage media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (k)(1)(i).

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation required by §63.1571(a) and (b), you must submit the results of the performance evaluation following the procedure specified in either paragraph (k)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI is accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being submitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive or other commonly used electronic storage media to the EPA. The electronic storage media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (k)(2)(i).

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in §63.13.

[67 FR 17773, Apr. 11, 2002, as amended at 80 FR 75278, Dec. 1, 2015]

§63.1576 What records must I keep, in what form, and for how long?

(a) You must keep the records specified in 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 that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) The records specified in paragraphs (a)(2)(i) through (iv) of this section.

(i) Record the date, time, and duration of each startup and/or shutdown period, recording the periods when the affected source was subject to the standard applicable to startup and shutdown.

(ii) In the event that an affected unit fails to meet an applicable standard, record the number of failures. For each failure record the date, time and duration of each failure.

(iii) For each failure to meet an applicable standard, record and retain a list of the affected sources or equipment, an estimate of the volume of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions.

(iv) Record actions taken to minimize emissions in accordance with §63.1570(c) and any corrective actions taken to return the affected unit to its normal or usual manner of operation.

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

(b) For each continuous emission monitoring system and continuous opacity monitoring system, you must keep the records required in paragraphs (b)(1) through (5) of this section.

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

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

(3) The performance evaluation plan as described in §63.8(d)(2) for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Administrator. If the performance evaluation plan is revised, you must keep previous (*i.e.,* superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan. The program of corrective action should be included in the plan required under §63.8(d)(2).

(4) Requests for alternatives to the relative accuracy test for continuous emission monitoring systems as required in §63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped.

(c) You must keep the records in §63.6(h) for visible emission observations.

(d) You must keep records required by Tables 6, 7, 13, and 14 of this subpart (for catalytic cracking units); 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 emission limitation that applies to you.

(e) You must keep a current copy of your operation, maintenance, and monitoring plan onsite and available for inspection. You also must keep records to show continuous compliance with the procedures in your operation, maintenance, and monitoring plan.

(f) You also must 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.

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

(h) As specified in §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.

(i) 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 §63.10(b)(1). You can keep the records offsite for the remaining 3 years.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005; 80 FR 75279, Dec. 1, 2015]

Other Requirements and Information

§63.1577 What parts of the General Provisions apply to me?

Table 44 of this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§63.1578 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by us, the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. 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 contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are listed in paragraphs (c)(1) through (5) of this section.

(1) Approval of alternatives to the non-opacity emission limitations and work practice standards in §§63.1564 through 63.1569 under §63.6(g).

(2) Approval of alternative opacity emission limitations in §§63.1564 through 63.1569 under §63.6(h)(9).

(3) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

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

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

§63.1579 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in 40 CFR 63.2, the General Provisions of this part (§§63.1 through 63.15), and in this section as listed. If the same term is defined in subpart A of this part and in this section, it shall have the meaning given in this section for purposes of this subpart.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator.

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 regenerated by burning off coke and other deposits. The unit includes, but is not limited to, 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 equipment used for heat recovery.

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

Catalytic reforming unit means a refinery process unit that reforms or changes the chemical structure of naphtha into higher octane aromatics through the use of a metal catalyst and chemical reactions that include dehydrogenation, isomerization, and hydrogenolysis. The catalytic reforming unit includes the reactor, regenerator (if separate), separators, catalyst isolation and transport vessels (e.g., lock and lift hoppers), recirculation equipment, scrubbers, and other ancillary equipment.

Catalytic reforming unit regenerator means one or more regenerators which comprise that portion of the catalytic reforming unit and ancillary equipment in which the following regeneration steps typically are performed: depressurization, purge, coke burn-off, catalyst rejuvenation with a chloride (or other halogenated) compound(s), and a final purge. The catalytic reforming unit catalyst regeneration process can be done either as a semi-regenerative, cyclic, or continuous regeneration process.

Coke burn-off means the coke removed from the surface of the catalytic cracking unit catalyst or the catalytic reforming unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated using Equation 2 in §63.1564.

Combustion device means an individual unit of equipment such as a flare, incinerator, process heater, or boiler used for the destruction of organic HAP or VOC.

Combustion zone means the space in an enclosed combustion device (e.g., vapor incinerator, boiler, furnace, or process heater) occupied by the organic HAP and any supplemental fuel while burning. The combustion zone includes any flame that is visible or luminous as well as that space outside the flame envelope in which the organic HAP continues to be oxidized to form the combustion products.

Contact material means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminants from petroleum derivatives.

Continuous regeneration reforming means a catalytic reforming process characterized by continuous flow of catalyst material through a reactor where it mixes with feedstock, and a portion of the catalyst is continuously removed and sent to a special regenerator where it is regenerated and continuously recycled back to the reactor.

Control device means any equipment used for recovering, removing, or oxidizing HAP in either gaseous or solid form. Such equipment includes, but is not limited to, condensers, scrubbers, electrostatic precipitators, incinerators, flares, boilers, and process heaters.

Cyclic regeneration reforming means a catalytic reforming process characterized by continual batch regeneration of catalyst in situ in any one of several reactors (e.g., 4 or 5 separate reactors) that can be isolated from and returned to the reforming operation while maintaining continuous reforming process operations (i.e., feedstock continues flowing through the remaining reactors without change in feed rate or product octane).

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) 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; or

(2) 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.

Emission limitation means any emission limit, opacity limit, operating limit, or visible emission limit.

Flame zone means the portion of a combustion chamber of a boiler or process heater occupied by the flame envelope created by the primary fuel.

Flow indicator means a device that indicates whether gas is flowing, or whether the valve position would allow gas to flow, in or through a line.

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous streams generated by the source, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric. The gaseous streams can contain a mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species.

HCl means for the purposes of this subpart, gaseous emissions of hydrogen chloride that serve as a surrogate measure for total emissions of hydrogen chloride and chlorine as measured by Method 26 or 26A in appendix A to part 60 of this chapter or an approved alternative method.

Hot standby means periods when the catalytic cracking unit is not receiving fresh or recycled feed oil but the catalytic cracking unit is maintained at elevated temperatures, typically using torch oil in the catalyst regenerator and recirculating catalyst, to prevent a complete shutdown and cold restart of the catalytic cracking unit.

Incinerator means an enclosed combustion device that is used for destroying organic compounds, with or without heat recovery. Auxiliary fuel may be used to heat waste gas to combustion temperatures. An incinerator may use a catalytic combustion process where a substance is introduced into an exhaust stream to burn or oxidize contaminants while the substances itself remains intact, or a thermal process which uses elevated temperatures as a primary means to burn or oxidize contaminants.

Internal scrubbing system means a wet scrubbing, wet injection, or caustic injection control device that treats (in-situ) the catalytic reforming unit recirculating coke burn exhaust gases for acid (HCl) control during reforming catalyst regeneration upstream of the atmospheric coke burn vent.

Ni means, for the purposes of this subpart, particulate emissions of nickel that serve as a surrogate measure for total emissions of metal HAP, including but not limited to: antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium as measured by Method 29 in appendix A to part 60 of this chapter or by an approved alternative method.

Nonmethane TOC means, for the purposes of this subpart, emissions of total organic compounds, excluding methane, that serve as a surrogate measure of the total emissions of organic HAP compounds including, but not limited to, acetaldehyde, benzene, hexane, phenol, toluene, and xylenes and nonHAP VOC as measured by Method 25 in appendix A to part 60 of this chapter, by the combination of Methods 18 and 25A in appendix A to part 60 of this chapter, or by an approved alternative method.

Oxidation control system means an emission control system which reduces emissions from sulfur recovery units by converting these emissions to sulfur dioxide.

PM means, for the purposes of this subpart, emissions of particulate matter that serve as a surrogate measure of the total emissions of particulate matter and metal HAP contained in the particulate matter, including but not limited to: Antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium as measured by Methods 5, 5B or 5F in appendix A-3 to part 60 of this chapter or by an approved alternative method.

Process heater means an enclosed combustion device that primarily transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water.

Process vent means, for the purposes of this subpart, a gas stream that is continuously or periodically discharged during normal operation of a catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit, including gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device line prior to control or discharge to the atmosphere.

Reduced sulfur compounds means hydrogen sulfide, carbonyl sulfide, and carbon disulfide.

Reduction control system means an emission control system which reduces emissions from sulfur recovery units by converting these emissions to hydrogen sulfide.

Responsible official means responsible official as defined in 40 CFR 70.2.

Semi-regenerative reforming means a catalytic reforming process characterized by shutdown of the entire reforming unit (e.g., which may employ three to four separate reactors) at specified intervals or at the owner's or operator's convenience for in situ catalyst regeneration.

Sulfur recovery unit means a process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide. This definition does not include a unit where the modified reaction is carried out in a water solution which contains a metal ion capable of oxidizing the sulfide ion to sulfur, e.g., the LO-CAT II process.

TOC means, for the purposes of this subpart, emissions of total organic compounds that serve as a surrogate measure of the total emissions of organic HAP compounds including, but not limited to, acetaldehyde, benzene, hexane, phenol, toluene, and xylenes and nonHAP VOC as measured by Method 25A in appendix A to part 60 of this chapter or by an approved alternative method.

TRS means, for the purposes of this subpart, emissions of total reduced sulfur compounds, expressed as an equivalent sulfur dioxide concentration, that serve as a surrogate measure of the total emissions of sulfide HAP carbonyl sulfide and carbon disulfide as measured by Method 15 in appendix A to part 60 of this chapter or by an approved alternative method.

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.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005; 80 FR 75279, Dec. 1, 2015]

Table 1 to Subpart UUU of Part 63—Metal HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1564(a)(1), you shall meet each emission limitation in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	**You shall meet the following emission limits for each catalyst regenerator vent . . .**
1. Subject to new source performance standard (NSPS) for PM in 40 CFR 60.102 and not electing §60.100(e)	PM emissions must not exceed 1.0 gram per kilogram (g/kg) (1.0 lb/1,000 lb) of coke burn-off, and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. Before August 1, 2017, if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or in supplemental liquid or solid fossil fuel, the incremental rate of PM emissions must not exceed 43.0 grams per Gigajoule (g/GJ) or 0.10 pounds per million British thermal units (lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i); or 40 CFR 60.102 and electing §60.100(e)	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off or, if a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii)	PM emissions must not exceed 0.5 g/kg coke burn-off (0.5 lb/1000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air.
4. Option 1a: Elect NSPS subpart J requirements for PM per coke burn limit and 30% opacity, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed the limits specified in Item 1 of this table.
5. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1000 lb) of coke burn-off.

For each new or existing catalytic cracking unit . . .	**You shall meet the following emission limits for each catalyst regenerator vent . . .**
6. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 0.040 gr/dscf corrected to 0 percent excess air.
7. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1000 lb) of coke burn-off in the catalyst regenerator.
8. Option 3: Ni lb/hr limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Nickel (Ni) emissions must not exceed 13,000 milligrams per hour (mg/hr) (0.029 lb/hr).
9. Option 4: Ni per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Ni emissions must not exceed 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator.

[80 FR 75280, Dec. 1, 2015]

Table 2 to Subpart UUU of Part 63—Operating Limits for Metal HAP Emissions From Catalytic Cracking Units

As stated in §63.1564(a)(2), you shall meet each operating limit in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	**For this type of continuous monitoring system . . .**	**For this type of control device . . .**	**You shall meet this operating limit . . .**
1. Subject to the NSPS for PM in 40 CFR 60.102 and not elect §60.100(e)	Continuous opacity monitoring system	Any	On and after August 1, 2017, maintain the 3-hour rolling average opacity of emissions from your catalyst regenerator vent no higher than 20 percent.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i) or electing §60.100(e)	a. PM CEMS	Any	Not applicable.
	b. Continuous opacity monitoring system used to comply with a site-specific opacity limit	Cyclone or electrostatic precipitator	Maintain the 3-hour rolling average opacity of emissions from your catalyst regenerator vent no higher than the site-specific opacity limit established during the performance test.
	c. Continuous parameter monitoring systems	Electrostatic precipitator	i. Maintain the daily average coke burn-off rate or daily average flow rate no higher than the limit established in the performance test.
			ii. Maintain the 3-hour rolling average total power and secondary current above the limit established in the performance test.
	d. Continuous parameter monitoring systems	Wet scrubber	i. Maintain the 3-hour rolling average liquid-to-gas ratio above the limit established in the performance test.
			ii. Except for periods of startup, shutdown, and hot standby, maintain the 3-hour rolling average pressure drop above the limit established in the performance test.[1]

For each new or existing catalytic cracking unit . . .	For this type of continuous monitoring system . . .	For this type of control device . . .	You shall meet this operating limit . . .
	e. Bag leak detection (BLD) system	Fabric filter	Maintain particulate loading below the BLD alarm set point established in the initial adjustment of the BLD system or allowable seasonal adjustments.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii)	Any	Any	The applicable operating limits in Item 2 of this table.
4. Option 1a: Elect NSPS subpart J requirements for PM per coke burn limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Any	Any	See Item 1 of this table.
5. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Any	Any	The applicable operating limits in Item 2.b, 2.c, 2.d, and 2.e of this table.
6. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM CEMS	Any	Not applicable.
7. Option 2: PM per coke burn-off limit not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	a. Continuous opacity monitoring system used to comply with a site-specific opacity limit	Cyclone, fabric filter, or electrostatic precipitator	See Item 2.b of this table. Alternatively, before August 1, 2017, you may maintain the hourly average opacity of emissions from your catalyst generator vent no higher than the site-specific opacity limit established during the performance test.
	b. Continuous parameter monitoring systems	i. Electrostatic precipitator	(1) See Item 2.c.i of this table. (2) See item 2.c.ii of this table. Alternatively, before August 1, 2017, you may maintain the daily average voltage and secondary current above the limit established in the performance test.
		ii. Wet scrubber	(1) See Item 2.d.i of this table. Alternatively, before August 1, 2017, you may maintain the daily average liquid-to-gas ratio above the limit established in the performance test. (2) See Item 2.d.ii of the table. Alternatively, before August 1, 2017, you may maintain the daily average pressure drop above the limit established in the performance test (not applicable to a wet scrubber of the non-venturi jet-ejector design).
	c. Bag leak detection (BLD) system	Fabric filter	See item 2.e of this table.

For each new or existing catalytic cracking unit . . .	**For this type of continuous monitoring system . . .**	**For this type of control device . . .**	**You shall meet this operating limit . . .**
8. Option 3: Ni lb/hr limit not subject to the NSPS for PM in 40 CFR 60.102	a. Continuous opacity monitoring system	Cyclone, fabric filter, or electrostatic precipitator	Maintain the 3-hour rolling average Ni operating value no higher than the limit established during the performance test. Alternatively, before August 1, 2017, you may maintain the daily average Ni operating value no higher than the limit established during the performance test.
	b. Continuous parameter monitoring systems	i. Electrostatic precipitator	(1) See Item 2.c.i of this table. (2) Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test.
			(3) See Item 2.c.ii of this table. Alternatively, before August 1, 2017, you may maintain the daily average voltage and secondary current (or total power input) above the established during the performance test.
		ii. Wet scrubber	(1) Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test.
			(2) See Item 2.d.i of this table. Alternatively, before August 1, 2017, you may maintain the daily average liquid-to-gas ratio above the limit established during the performance test.
			(3) See Item 2.d.ii of this table. Alternatively, before August 1, 2017, you may maintain the daily average pressure drop above the limit established during the performance test (not applicable to a non-venturi wet scrubber of the jet-ejector design).
	c. Bag leak detection (BLD) system	Fabric filter	See item 2.e of this table.
9. Option 4: Ni per coke burn-off limit not subject to the NSPS for PM in 40 CFR 60.102	a. Continuous opacity monitoring system	Cyclone, fabric filter, or electrostatic precipitator	Maintain the 3-hour rolling average Ni operating value no higher than Ni operating limit established during the performance test. Alternatively, before August 1, 2017, you may elect to maintain the daily average Ni operating value no higher than the Ni operating limit established during the performance test.
	b. Continuous parameter monitoring systems	i. Electrostatic precipitator	(1) Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test.
			(2) See Item 2.c.ii of this table. Alternatively, before August 1, 2017, you may maintain the daily average voltage and secondary current (or total power input) above the limit established during the performance test.

For each new or existing catalytic cracking unit . . .	For this type of continuous monitoring system . . .	For this type of control device . . .	You shall meet this operating limit . . .
		ii. Wet scrubber	(1) Maintain the monthly rolling average of the equilibrium catalyst Ni concentration no higher than the limit established during the performance test.
			(2) See Item 2.d.i of this table. Alternatively, before August 1, 2017, you may maintain the daily average liquid-to-gas ratio above the limit established during the performance test.
			(3) See Item 2.d.ii of this table. Alternatively, before August 1, 2017, you may maintain the daily average pressure drop above the limit established during the performance test (not applicable to a non-venturi wet scrubber of the jet-ejector design).
	c. Bag leak detection (BLD) system	Fabric filter	See item 2.e of this table.
10. During periods of startup, shutdown, or hot standby	Any	Any	Meet the requirements in §63.1564(a)(5).

[1] If you use a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles, you can use the alternative in §63.1573(b), and comply with the daily inspections, recordkeeping, and repair provisions, instead of a continuous parameter monitoring system for pressure drop across the scrubber.

[80 FR 75280, Dec. 1, 2015, as amended at 81 FR 45244, July 13, 2016]

Table 3 to Subpart UUU of Part 63—Continous Monitoring Systems for Metal HAP Emissions From Catalytic Cracking Units

As stated in §63.1564(b)(1), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	If you use this type of control device for your vent . . .	You shall install, operate, and maintain a . . .
1. Subject to the NSPS for PM in 40 CFR 60.102 and not electing §60.100(e)	Any	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i); or in §60.102 and electing §60.100(e); electing to meet the PM per coke burn-off limit	a. Cyclone b. Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent. Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent; or continuous parameter monitoring systems to measure and record the coke burn-off rate or the gas flow rate entering or exiting the control device,[1] the voltage, current, and secondary current to the control device.

For each new or existing catalytic cracking unit . . .	**If you use this type of control device for your vent . . .**	**You shall install, operate, and maintain a . . .**
	c. Wet scrubber	Continuous parameter monitoring system to measure and record the pressure drop across the scrubber,[2] the coke burn-off rate or the gas flow rate entering or exiting the control device,[3] and total liquid (or scrubbing liquor) flow rate to the control device.
	d. Fabric Filter	Continuous bag leak detection system to measure and record increases in relative particulate loading from each catalyst regenerator vent.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i); or in §60.102 and electing §60.100(e); electing to meet the PM concentration limit	Any	Continuous emission monitoring system to measure and record the concentration of PM and oxygen from each catalyst regenerator vent.
4. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii) electing to meet the PM per coke burn-off limit	Any	The applicable continuous monitoring systems in item 2 of this table.
5. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii) electing to meet the PM concentration limit	Any	See item 3 of this table.
6. Option 1a: Elect NSPS subpart J, PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.120a(b)(1)	Any	See item 1 of this table.
7. Option 1b: Elect NSPS subpart Ja, PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.120a(b)(1)	Any	The applicable continuous monitoring systems in item 2 of this table.
8. Option 1c: Elect NSPS subpart Ja, PM concentration limit not subject to the NSPS for PM in 40 CFR 60.102 or 60.120a(b)(1)	Any	See item 3 of this table.
9. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.120a(b)(1)	Any	The applicable continuous monitoring systems in item 2 of this table.
10. Option 3: Ni lb/hr limit not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	a. Cyclone	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device.[1]
	b. Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the control device[1]; or continuous parameter monitoring systems to measure and record the coke burn-off rate or the gas flow rate entering or exiting the control device[1] and the voltage and current (to measure the total power to the system) and secondary current to the control device.

For each new or existing catalytic cracking unit . . .	If you use this type of control device for your vent . . .	You shall install, operate, and maintain a . . .
	c. Wet scrubber	Continuous parameter monitoring system to measure and record the pressure drop across the scrubber,[2] gas flow rate entering or exiting the control device,[1] and total liquid (or scrubbing liquor) flow rate to the control device.
	d. Fabric Filter	Continuous bag leak detection system to measure and record increases in relative particulate loading from each catalyst regenerator vent or the monitoring systems specified in item 10.a of this table.
11. Option 4: Ni per coke burn-off limit not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	a. Cyclone	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the coke burn-off rate and the gas flow rate entering or exiting the control device.[1]
	b. Electrostatic precipitator	Continuous opacity monitoring system to measure and record the opacity of emissions from each catalyst regenerator vent and continuous parameter monitoring system to measure and record the coke burn-off rate and the gas flow rate entering or exiting the control device[1]; or continuous parameter monitoring systems to measure and record the coke burn-off rate or the gas flow rate entering or exiting the control device[1] and voltage and current (to measure the total power to the system) and secondary current to the control device.
	c. Wet scrubber	Continuous parameter monitoring system to measure and record the pressure drop across the scrubber,[2] gas flow rate entering or exiting the control device,[1] and total liquid (or scrubbing liquor) flow rate to the control device.
	d. Fabric Filter	Continuous bag leak detection system to measure and record increases in relative particulate loading from each catalyst regenerator vent or the monitoring systems specified in item 11.a of this table.
12. Electing to comply with the operating limits in §63.1564(a)(5)(ii) during periods of startup, shutdown, or hot standby	Any	Continuous parameter monitoring system to measure and record the gas flow rate exiting the catalyst regenerator.[1]

[1] If applicable, you can use the alternative in §63.1573(a)(1) instead of a continuous parameter monitoring system for gas flow rate.

[2] If you use a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles, you can use the alternative in §63.1573(b) instead of a continuous parameter monitoring system for pressure drop across the scrubber.

[80 FR 75283, Dec. 1, 2015, as amended at 81 FR 45244, July 13, 2016]

Table 4 to Subpart UUU of Part 63—Requirements for Performance Tests for Metal HAP Emissions From Catalytic Cracking Units

As stated in §§63.1564(b)(2) and 63.1571(a)(5), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	**You must . . .**	**Using . . .**	**According to these requirements . . .**
1. Any	a. Select sampling port's location and the number of traverse ports	Method 1 or 1A in appendix A-1 to part 60 of this chapter	Sampling sites must be located at the outlet of the control device or the outlet of the regenerator, as applicable, and prior to any releases to the atmosphere.
	b. Determine velocity and volumetric flow rate	Method 2, 2A, 2C, 2D, or 2F in appendix A-1 to part 60 of this chapter, or Method 2G in appendix A-2 to part 60 of this chapter, as applicable	
	c. Conduct gas molecular weight analysis	Method 3, 3A, or 3B in appendix A-2 to part 60 of this chapter, as applicable	
	d. Measure moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter	
	e. If you use an electrostatic precipitator, record the total number of fields in the control system and how many operated during the applicable performance test		
	f. If you use a wet scrubber, record the total amount (rate) of water (or scrubbing liquid) and the amount (rate) of make-up liquid to the scrubber during each test run		
2. Subject to the NSPS for PM in 40 CFR 60.102 and not elect §60.100(e)	a. Measure PM emissions	Method 5, 5B, or 5F (40 CFR part 60, appendix A-3) to determine PM emissions and associated moisture content for units without wet scrubbers. Method 5 or 5B (40 CFR part 60, appendix A-3) to determine PM emissions and associated moisture content for unit with wet scrubber	You must maintain a sampling rate of at least 0.15 dry standard cubic meters per minute (dscm/min) (0.53 dry standard cubic feet per minute (dscf/min)).

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	**You must . . .**	**Using . . .**	**According to these requirements . . .**
	b. Compute coke burn-off rate and PM emission rate (lb/1,000 lb of coke burn-off)	Equations 1, 2, and 3 of §63.1564 (if applicable)	
	c. Measure opacity of emissions	Continuous opacity monitoring system	You must collect opacity monitoring data every 10 seconds during the entire period of the Method 5, 5B, or 5F performance test and reduce the data to 6-minute averages.
3. Subject to the NSPS for PM in 40 CFR 60.102a(b)(1) or elect §60.100(e), electing the PM for coke burn-off limit	a. Measure PM emissions	Method 5, 5B, or 5F (40 CFR part 60, appendix A-3) to determine PM emissions and associated moisture content for units without wet scrubbers. Method 5 or 5B (40 CFR part 60, appendix A-3) to determine PM emissions and associated moisture content for unit with wet scrubber	You must maintain a sampling rate of at least 0.15 dscm/min (0.53 dscf/min).
	b. Compute coke burn-off rate and PM emission rate (lb/1,000 lb of coke burn-off)	Equations 1, 2, and 3 of §63.1564 (if applicable)	
	c. Establish site-specific limit if you use a COMS	Continuous opacity monitoring system	If you elect to comply with the site-specific opacity limit in §63.1564(b)(4)(i), you must collect opacity monitoring data every 10 seconds during the entire period of the Method 5, 5B, or 5F performance test. For site specific opacity monitoring, reduce the data to 6-minute averages; determine and record the average opacity for each test run; and compute the site-specific opacity limit using Equation 4 of §63.1564.
4. Subject to the NSPS for PM in 40 CFR 60.102a(b)(1) or elect §60.100(e)	a. Measure PM emissions	Method 5, 5B, or 5F (40 CFR part 60, appendix A-3) to determine PM emissions and associated moisture content for units without wet scrubbers. Method 5 or 5B (40 CFR part 60, appendix A-3) to determine PM emissions and associated moisture content for unit with wet scrubber	You must maintain a sampling rate of at least 0.15 dscm/min (0.53 dscf/min).

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	**You must . . .**	**Using . . .**	**According to these requirements . . .**
5. Option 1a: Elect NSPS subpart J requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	See item 2 of this table.		
6. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	See item 3 of this table		
7. Option 1c: Elect NSPS requirements for PM concentration, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	See item 4 of this table		
8. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	See item 3 of this table		
9. Option 3: Ni lb/hr limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	a. Measure concentration of Ni b. Compute Ni emission rate (lb/hr)	Method 29 (40 CFR part 60, appendix A-8) Equation 5 of §63.1564	
	c. Determine the equilibrium catalyst Ni concentration	XRF procedure in appendix A to this subpart1; or EPA Method 6010B or 6020 or EPA Method 7520 or 7521 in SW-8462; or an alternative to the SW-846 method satisfactory to the Administrator	You must obtain 1 sample for each of the 3 test runs; determine and record the equilibrium catalyst Ni concentration for each of the 3 samples; and you may adjust the laboratory results to the maximum value using Equation 2 of §63.1571.
	d. If you use a continuous opacity monitoring system, establish your site-specific Ni operating limit	i. Equations 6 and 7 of §63.1564 using data from continuous opacity monitoring system, gas flow rate, results of equilibrium catalyst Ni concentration analysis, and Ni emission rate from Method 29 test	(1) You must collect opacity monitoring data every 10 seconds during the entire period of the initial Ni performance test; reduce the data to 6-minute averages; and determine and record the average opacity from all the 6-minute averages for each test run.

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	**You must . . .**	**Using . . .**	**According to these requirements . . .**
			(2) You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial Ni performance test; measure the gas flow as near as practical to the continuous opacity monitoring system; and determine and record the hourly average actual gas flow rate for each test run.
10. Option 4: Ni per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	a. Measure concentration of Ni. b. Compute Ni emission rate (lb/1,000 lb of coke burn-off)	Method 29 (40 CFR part 60, appendix A-8). Equations 1 and 8 of §63.1564	
	c. Determine the equilibrium catalyst Ni concentration	See item 6.c. of this table	You must obtain 1 sample for each of the 3 test runs; determine and record the equilibrium catalyst Ni concentration for each of the 3 samples; and you may adjust the laboratory results to the maximum value using Equation 2 of §63.1571.
	d. If you use a continuous opacity monitoring system, establish your site-specific Ni operating limit	i. Equations 9 and 10 of §63.1564 with data from continuous opacity monitoring system, coke burn-off rate, results of equilibrium catalyst Ni concentration analysis, and Ni emission rate from Method 29 test	(1) You must collect opacity monitoring data every 10 seconds during the entire period of the initial Ni performance test; reduce the data to 6-minute averages; and determine and record the average opacity from all the 6-minute averages for each test run.
			(2) You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial Ni performance test; measure the gas flow rate as near as practical to the continuous opacity monitoring system; and determine and record the hourly average actual gas flow rate for each test run.
	e. Record the catalyst addition rate for each test and schedule for the 10-day period prior to the test		

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	**You must . . .**	**Using . . .**	**According to these requirements . . .**
11. If you elect item 5 Option 1b in Table 1, item 7 Option 2 in Table 1, item 8 Option 3 in Table 1, or item 9 Option 4 in Table 1 of this subpart and you use continuous parameter monitoring systems	a. Establish each operating limit in Table 2 of this subpart that applies to you	Data from the continuous parameter monitoring systems and applicable performance test methods	
	b. Electrostatic precipitator or wet scrubber: Gas flow rate	i. Data from the continuous parameter monitoring systems and applicable performance test methods	(1) You must collect gas flow rate monitoring data every 15 minutes during the entire period of the initial performance test; determine and record the average gas flow rate for each test run.
			(2) You must determine and record the 3-hr average gas flow rate from the test runs. Alternatively, before August 1, 2017, you may determine and record the maximum hourly average gas flow rate from all the readings.
	c. Electrostatic precipitator: Total power (voltage and current) and secondary current	i. Data from the continuous parameter monitoring systems and applicable performance test methods	(1) You must collect voltage, current, and secondary current monitoring data every 15 minutes during the entire period of the performance test; and determine and record the average voltage, current, and secondary current for each test run. Alternatively, before August 1, 2017, you may collect voltage and secondary current (or total power input) monitoring data every 15 minutes during the entire period of the initial performance test.
			(2) You must determine and record the 3-hr average total power to the system for the test runs and the 3-hr average secondary current from the test runs. Alternatively, before August 1, 2017, you may determine and record the minimum hourly average voltage and secondary current (or total power input) from all the readings.
	d. Electrostatic precipitator or wet scrubber: Equilibrium catalyst Ni concentration	Results of analysis for equilibrium catalyst Ni concentration	You must determine and record the average equilibrium catalyst Ni concentration for the 3 runs based on the laboratory results. You may adjust the value using Equation 1 or 2 of §63.1571 as applicable.

For each new or existing catalytic cracking unit catalyst regenerator vent . . .	**You must . . .**	**Using . . .**	**According to these requirements . . .**
	e. Wet scrubber: Pressure drop (not applicable to non-venturi scrubber of jet ejector design)	i. Data from the continuous parameter monitoring systems and applicable performance test methods	(1) You must collect pressure drop monitoring data every 15 minutes during the entire period of the initial performance test; and determine and record the average pressure drop for each test run. (2) You must determine and record the 3-hr average pressure drop from the test runs. Alternatively, before August 1, 2017, you may determine and record the minimum hourly average pressure drop from all the readings.
	f. Wet scrubber: Liquid-to-gas ratio	i. Data from the continuous parameter monitoring systems and applicable performance test methods	(1) You must collect gas flow rate and total water (or scrubbing liquid) flow rate monitoring data every 15 minutes during the entire period of the initial performance test; determine and record the average gas flow rate for each test run; and determine the average total water (or scrubbing liquid) flow for each test run.
			(2) You must determine and record the hourly average liquid-to-gas ratio from the test runs. Alternatively, before August 1, 2017, you may determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate from all the readings.
			(3) You must determine and record the 3-hr average liquid-to-gas ratio. Alternatively, before August 1, 2017, you may determine and record the minimum liquid-to-gas ratio.
	g. Alternative procedure for gas flow rate	i. Data from the continuous parameter monitoring systems and applicable performance test methods	(1) You must collect air flow rate monitoring data or determine the air flow rate using control room instrumentation every 15 minutes during the entire period of the initial performance test.
			(2) You must determine and record the 3-hr average rate of all the readings from the test runs. Alternatively, before August 1, 2017, you may determine and record the hourly average rate of all the readings.
			(3) You must determine and record the maximum gas flow rate using Equation 1 of §63.1573.

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[1] Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure).

[2] EPA Method 6010B, Inductively Coupled Plasma-Atomic Emission Spectrometry, EPA Method 6020, Inductively Coupled Plasma-Mass Spectrometry, EPA Method 7520, Nickel Atomic Absorption, Direct Aspiration, and EPA Method 7521, Nickel Atomic Absorption, Direct Aspiration are included in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication SW-846, Revision 5 (April 1998). The SW-846 and Updates (document number 955-001-00000-1) are available for purchase from the Superintendent of Documents, U.S. Government Publishing Office, Washington, DC 20402, (202) 512-1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487-4650. Copies may be inspected at the EPA Docket Center, William Jefferson Clinton (WJC) West Building, (Air Docket), Room 3334, 1301 Constitution Ave. NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street NW., Suite 700, Washington, DC.

[80 FR 75285, Dec. 1, 2015]

Table 5 to Subpart UUU of Part 63—Initial Compliance With Metal HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1564(b)(5), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit catalyst regenerator vent . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Subject to the NSPS for PM in 40 CFR 60.102 and not electing §60.100(e)	PM emissions must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off, and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. Before August 1, 2017, if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ or 0.10 lb/million Btu of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM emission rate is less than or equal to 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. You have already conducted a performance test to demonstrate initial compliance with the NSPS and the average hourly opacity is no more than 30 percent, except that one 6-minute average in any 1-hour period can exceed 30 percent. As part of the Notification of Compliance Status, you must certify that your vent meets the 30 percent opacity limit. As part of your Notification of Compliance Status, you certify that your continuous opacity monitoring system meets the requirements in §63.1572.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i); or in §60.102 and electing §60.100(e) and electing to meet the PM per coke burn-off limit	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM emission rate is less than or equal to 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. As part of your Notification of Compliance Status, you certify that your BLD; CO_2, O_2, or CO monitor; or continuous opacity monitoring system meets the requirements in §63.1572.

For each new and existing catalytic cracking unit catalyst regenerator vent . . .	**For the following emission limit . . .**	**You have demonstrated initial compliance if . . .**
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i), electing to meet the PM per coke burn-off limit	PM emissions must not exceed 0.5 g/kg (0.5 lb PM/1,000 lb) of coke burn-off)	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM emission rate is less than or equal to 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. As part of your Notification of Compliance Status, you certify that your BLD; CO_2, O_2, or CO monitor; or continuous opacity monitoring system meets the requirements in §63.1572.
4. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i), electing to meet the PM concentration limit	If a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM concentration is less than or equal to 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. As part of your Notification of Compliance Status, you certify that your PM CEMS meets the requirements in §63.1572.
5. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii), electing to meet the PM concentration limit	If a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured PM concentration is less than or equal to 0.020 gr/dscf corrected to 0 percent excess air. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. You are not required to do another performance test to demonstrate initial compliance. As part of your Notification of Compliance Status, you certify that your PM CEMS meets the requirements in §63.1572.

For each new and existing catalytic cracking unit catalyst regenerator vent . . .	**For the following emission limit . . .**	**You have demonstrated initial compliance if . . .**
6. Option 1a: Elect NSPS subpart J requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 1.0 gram per kilogram (g/kg) (1.0 lb/1,000 lb) of coke burn-off, and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. Before August 1, 2017, PM emission must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off in the catalyst regenerator; if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period	The average PM emission rate, measured using EPA Method 5, 5B, or 5F (for a unit without a wet scrubber) or 5 or 5B (for a unit with a wet scrubber) (40 CFR part 60, appendix A-3), over the period of the initial performance test, is no higher than 1.0 g/kg coke burn-off (1.0 lb/1,000 lb) in the catalyst regenerator. The PM emission rate is calculated using Equations 1, 2, and 3 of §63.1564. As part of the Notification of Compliance Status, you must certify that your vent meets the PM limit. The average hourly opacity is no more than 30 percent, except that one 6-minute average in any 1-hour period can exceed 30 percent. As part of the Notification of Compliance Status, you must certify that your vent meets the 30 percent opacity limit. If you use a continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in §63.1572.
7. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off	The average PM emission rate, measured using EPA Method 5, 5B, or 5F (for a unit without a wet scrubber) or 5 or 5B (for a unit with a wet scrubber) (40 CFR part 60, appendix A-3), over the period of the initial performance test, is no higher than 1.0 g/kg coke burn-off (1.0 lb/1,000 lb) in the catalyst regenerator. The PM emission rate is calculated using Equations 1, 2, and 3 of §63.1564. If you use a BLD; CO_2, O_2, CO monitor; or continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in §63.1572.
8. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 0.040 gr/dscf corrected to 0 percent excess air	The average PM concentration, measured using EPA Method 5, 5B, or 5F (for a unit without a wet scrubber) or Method 5 or 5B (for a unit with a wet scrubber) (40 CFR part 60, appendix A-3), over the period of the initial performance test, is less than or equal to 0.040 gr/dscf corrected to 0 percent excess air. Your performance evaluation shows your PM CEMS meets the applicable requirements in §63.1572.

For each new and existing catalytic cracking unit catalyst regenerator vent . . .	**For the following emission limit . . .**	**You have demonstrated initial compliance if . . .**
9. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off	The average PM emission rate, measured using EPA Method 5, 5B, or 5F (for a unit without a wet scrubber) or 5 or 5B (for a unit with a wet scrubber) (40 CFR part 60, appendix A-3), over the period of the initial performance test, is no higher than 1.0 g/kg coke burn-off (1.0 lb/1,000 lb) in the catalyst regenerator. The PM emission rate is calculated using Equations 1, 2, and 3 of §63.1564. If you use a BLD; CO_2, O_2, CO monitor; or continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in §63.1572.
10. Option 3: Ni lb/hr limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Nickel (Ni) emissions from your catalyst regenerator vent must not exceed 13,000 mg/hr (0.029 lb/hr)	The average Ni emission rate, measured using Method 29 (40 CFR part 60, appendix A-8) over the period of the initial performance test, is not more than 13,000 mg/hr (0.029 lb/hr). The Ni emission rate is calculated using Equation 5 of §63.1564; and if you use a BLD; CO_2, O_2, or CO monitor; or continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in §63.1572.
11. Option 4: Ni per coke burn-off limit not subject to the NSPS for PM	Ni emissions from your catalyst regenerator vent must not exceed 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator	The average Ni emission rate, measured using Method 29 (40 CFR part 60, appendix A-8) over the period of the initial performance test, is not more than 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator. The Ni emission rate is calculated using Equation 8 of §63.1564; and if you use a BLD; CO_2, O_2, or CO monitor; or continuous opacity monitoring system, your performance evaluation shows the system meets the applicable requirements in §63.1572.

[80 FR 75290, Dec. 1, 2015, as amended at 81 FR 45244, July 13, 2016]

Table 6 to Subpart UUU of Part 63—Continuous Compliance With Metal HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1564(c)(1), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	You shall demonstrate continuous compliance by . . .
1. Subject to the NSPS for PM in 40 CFR 60.102 and not electing §60.100(e)	a. PM emissions must not exceed 1.0 g/kg (1.0 lb/1,000 lb) of coke burn-off, and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period. Before August 1, 2017, if the discharged gases pass through an incinerator or waste heat boiler in which you burn auxiliary or supplemental liquid or solid fossil fuel, the incremental rate of PM must not exceed 43.0 g/GJ (0.10 lb/million Btu) of heat input attributable to the liquid or solid fossil fuel; and the opacity of emissions must not exceed 30 percent, except for one 6-minute average opacity reading in any 1-hour period	i. Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) using Equation 1 in §63.1564 and the hours of operation for each catalyst regenerator.
		ii. Conducting a performance test before August 1, 2017 and thereafter following the testing frequency in §63.1571(a)(5) as applicable to your unit.
		iii. Collecting the continuous opacity monitoring data for each catalyst regenerator vent according to §63.1572 and maintaining each 6-minute average at or below 30 percent, except that one 6-minute average during a 1-hour period can exceed 30 percent.
		iv. Before August 1, 2017, if applicable, determining and recording each day the rate of combustion of liquid or solid fossil fuels (liters/hour or kilograms/hour) and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator-waste heat boiler; if applicable, maintaining the incremental rate of PM at or below 43 g/GJ (0.10 lb/million Btu) of heat input attributable to the solid or liquid fossil fuel.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i), electing to meet the PM per coke burn-off limit	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off	Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) using Equation 1 in §63.1564 and the hours of operation for each catalyst regenerator; maintaining PM emission rate below 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off; and conducting a performance test once every year.

For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	You shall demonstrate continuous compliance by . . .
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii), electing to meet the PM per coke burn-off limit	PM emissions must not exceed 0.5 g/kg coke burn-off (0.5 lb/1000 lb coke burn-off)	Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) using Equation 1 in §63.1564 and the hours of operation for each catalyst regenerator; maintaining PM emission rate below 0.5 g/kg (0.5 lb/1,000 lb) of coke burn-off; and conducting a performance test once every year.
4. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(i), electing to meet the PM concentration limit	If a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air	Maintaining PM concentration below 0.040 gr/dscf corrected to 0 percent excess air.
5. Subject to NSPS for PM in 40 CFR 60.102a(b)(1)(ii), electing to meet the PM concentration limit	If a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air	Maintaining PM concentration below 0.020 gr/dscf corrected to 0 percent excess air.
6. Option 1a: Elect NSPS subpart J requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	See item 1 of this table	See item 1 of this table.
7. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit and 30% opacity, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off	See item 2 of this table.
8. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 0.040 gr/dscf corrected to 0 percent excess air	See item 4 of this table.
9. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM emissions must not exceed 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off	Determining and recording each day the average coke burn-off rate and the hours of operation and the hours of operation for each catalyst regenerator by Equation 1 of §63.1564 (you can use process data to determine the volumetric flow rate); maintaining PM emission rate below 1.0 g/kg (1.0 lb PM/1,000 lb) of coke burn-off; and conducting a performance test before August 1, 2017 and thereafter following the testing frequency in §63.1571(a)(5) as applicable to your unit.
10. Option 3: Ni lb/hr limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Ni emissions must not exceed 13,000 mg/hr (0.029 lb/hr)	Maintaining Ni emission rate below 13,000 mg/hr (0.029 lb/hr); and conducting a performance test before August 1, 2017 and thereafter following the testing frequency in §63.1571(a)(5) as applicable to your unit.

For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	You shall demonstrate continuous compliance by . . .
11. Option 4: Ni per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Ni emissions must not exceed 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator	Determining and recording each day the average coke burn-off rate (thousands of kilograms per hour) and the hours of operation for each catalyst regenerator by Equation 1 of §63.1564 (you can use process data to determine the volumetric flow rate); and maintaining Ni emission rate below 1.0 mg/kg (0.001 lb/1,000 lb) of coke burn-off in the catalyst regenerator; and conducting a performance test before August 1, 2017 and thereafter following the testing frequency in §63.1571(a)(5) as applicable to your unit.

[80 FR 75292, Dec. 1, 2015]

Table 7 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Metal HAP Emissions From Catalytic Cracking Units

As stated in §63.1564(c)(1), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
1. Subject to NSPS for PM in 40 CFR 60.102 and not electing §60.100(e)	Continuous opacity monitoring system	The 3-hour average opacity of emissions from your catalyst regenerator vent must not exceed 20 percent	Collecting the continuous opacity monitoring data for each regenerator vent according to §63.1572 and maintain each 3-hour rolling average opacity of emissions no higher than 20 percent.
2. Subject to NSPS for PM in 40 CFR 60.102a(b)(1); or 40 CFR 60.102 and elect §60.100(e), electing to meet the PM per coke burn-off limit	a. Continuous opacity monitoring system, used for site-specific opacity limit—Cyclone or electrostatic precipitator	The average opacity must not exceed the opacity established during the performance test	Collecting the hourly and 3-hr rolling average opacity monitoring data according to §63.1572; maintaining the 3-hr rolling average opacity at or above the site-specific limit established during the performance test.
	b. Continuous parametric monitoring systems—electrostatic precipitator	i. The average gas flow rate entering or exiting the control device must not exceed the operating limit established during the performance test	Collecting the hourly and daily average coke burn-off rate or average gas flow rate monitoring data according to §63.1572; and maintaining the daily average coke burn-off rate or average gas flow rate at or below the limit established during the performance test.
		ii. The average total power and secondary current to the control device must not fall below the operating limit established during the performance test	Collecting the hourly and 3-hr rolling average total power and secondary current monitoring data according to §63.1572; and maintaining the 3-hr rolling average total power and secondary current at or above the limit established during the performance test.

For each new or existing catalytic cracking unit . . .	**If you use . . .**	**For this operating limit . . .**	**You shall demonstrate continuous compliance by . . .**
	c. Continuous parametric monitoring systems—wet scrubber	i. The average liquid-to-gas ratio must not fall below the operating limit established during the performance test	Collecting the hourly and 3-hr rolling average gas flow rate and scrubber liquid flow rate monitoring data according to §63.1572; determining and recording the 3-hr liquid-to-gas ratio; and maintaining the 3-hr rolling average liquid-to-gas ratio at or above the limit established during the performance test.
		ii. Except for periods of startup, shutdown and hot standby, the average pressure drop across the scrubber must not fall below the operating limit established during the performance test	Collecting the hourly and 3-hr rolling average pressure drop monitoring data according to §63.1572; and except for periods of startup, shutdown and hot standby, maintaining the 3-hr rolling average pressure drop at or above the limit established during the performance test.
	d. BLD—fabric filter	Increases in relative particulate	Collecting and maintaining records of BLD system output; determining the cause of the alarm within 1 hour of the alarm; and alleviating the cause of the alarm within 3 hours by corrective action.
3. Subject to NSPS for PM in 40 CFR 60.102a(b)(1), electing to meet the PM concentration limit	PM CEMS	Not applicable	Complying with Table 6 of this subpart, item 4 or 5.
4. Option 1a: Elect NSPS subpart J requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	Continuous opacity monitoring system	The 3-hour average opacity of emissions from your catalyst regenerator vent must not exceed 20 percent	Collecting the 3-hr rolling average continuous opacity monitoring system data according to §63.1572; and maintaining the 3-hr rolling average opacity no higher than 20 percent.
5. Option 1b: Elect NSPS subpart Ja requirements for PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	a. Continuous opacity monitoring system	The opacity of emissions from your catalyst regenerator vent must not exceed the site-specific opacity operating limit established during the performance test	Collecting the 3-hr rolling average continuous opacity monitoring system data according to §63.1572; maintaining the 3-hr rolling average opacity at or below the site-specific limit.
	b. Continuous parametric monitoring systems—electrostatic precipitator	See item 2.b of this table	See item 2.b of this table.
	c. Continuous parametric monitoring systems—wet scrubber	See item 2.c of this table	See item 2.c of this table.

For each new or existing catalytic cracking unit . . .	**If you use . . .**	**For this operating limit . . .**	**You shall demonstrate continuous compliance by . . .**
	d. BLD—fabric filter	See item 2.d of this table	See item 2.d of this table.
6. Option 1c: Elect NSPS subpart Ja requirements for PM concentration limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	PM CEMS	Not applicable	Complying with Table 6 of this subpart, item 4.
7. Option 2: PM per coke burn-off limit, not subject to the NSPS for PM in 40 CFR 60.102 or 60.102a(b)(1)	a. Continuous opacity monitoring system	The opacity of emissions from your catalyst regenerator vent must not exceed the site-specific opacity operating limit established during the performance test	Collecting the hourly and 3-hr rolling average continuous opacity monitoring system data according to §63.1572; and maintaining the 3-hr rolling average opacity at or below the site-specific limit established during the performance test. Alternatively, before August 1, 2017, collecting the hourly average continuous opacity monitoring system data according to §63.1572; and maintaining the hourly average opacity at or below the site-specific limit.
	b. Continuous parameter monitoring systems—electrostatic precipitator	i. The average coke burn-off rate or average gas flow rate entering or exiting the control device must not exceed the operating limit established during the performance test	Collecting the hourly and daily average coke burn-off rate or gas flow rate monitoring data according to §63.1572; and maintaining the daily coke burn-off rate or average gas flow rate at or below the limit established during the performance test.
		ii. The average total power (voltage and current) and secondary current to the control device must not fall below the operating limit established during the performance test	Collecting the hourly and 3-hr rolling average total power and secondary current monitoring data according to §63.1572; and maintaining the 3-hr rolling average total power and secondary current at or above the limit established during the performance test. Alternatively, before August 1, 2017, collecting the hourly and daily average voltage and secondary current (or total power input) monitoring data according to §63.1572; and maintaining the daily average voltage and secondary current (or total power input) at or above the limit established during the performance test.

For each new or existing catalytic cracking unit . . .	**If you use . . .**	**For this operating limit . . .**	**You shall demonstrate continuous compliance by . . .**
	c. Continuous parameter monitoring systems—wet scrubber	i. The average liquid-to-gas ratio must not fall below the operating limit established during the performance test	Collecting the hourly and 3-hr rolling average gas flow rate and scrubber liquid flow rate monitoring data according to §63.1572; determining and recording the 3-hr liquid-to-gas ratio; and maintaining the 3-hr rolling average liquid-to-gas ratio at or above the limit established during the performance test. Alternatively, before August 1, 2017, collecting the hourly average gas flow rate and water (or scrubbing liquid) flow rate monitoring data according to §63.1572[1]; determining and recording the hourly average liquid-to-gas ratio; determining and recording the daily average liquid-to-gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test.
		ii. Except for periods of startup, shutdown and hot standby, the average pressure drop across the scrubber must not fall below the operating limit established during the performance test	Collecting the hourly and 3-hr rolling average pressure drop monitoring data according to §63.1572; and except for periods of startup, shutdown and hot standby, maintaining the 3-hr rolling average pressure drop at or above the limit established during the performance test. Alternatively, before August 1, 2017, collecting the hourly and daily average pressure drop monitoring data according to §63.1572; and maintaining the daily average pressure drop above the limit established during the performance test.
	d. BLD—fabric filter	See item 2.d of this table	See item 2.d of this table.
8. Option 3: Ni lb/hr limit not subject to the NSPS for PM in 40 CFR 60.102	a. Continuous opacity monitoring system	i. The daily average Ni operating value must not exceed the site-specific Ni operating limit established during the performance test	(1) Collecting the hourly average continuous opacity monitoring system data according to §63.1572; determining and recording equilibrium catalyst Ni concentration at least once a week[2]; collecting the hourly average gas flow rate monitoring data according to §63.1572[1]; and determining and recording the hourly average Ni operating value using Equation 11 of §63.1564.
			(2) Determining and recording the 3-hour rolling average Ni operating value and maintaining the 3-hour rolling average Ni operating value below the site-specific Ni operating limit established during the performance test. Alternatively, before August 1, 2017, determining and recording the daily average Ni operating value and maintaining the daily average Ni operating value below the site-specific Ni operating limit established during the performance test.

For each new or existing catalytic cracking unit . . .	**If you use . . .**	**For this operating limit . . .**	**You shall demonstrate continuous compliance by . . .**
	b. Continuous parameter monitoring systems—electrostatic precipitator	i. The average gas flow rate entering or exiting the control device must not exceed the operating limit established during the performance test	See item 7.b.i of this table.
		ii. The average total power (voltage and current) and secondary current must not fall below the level established in the performance test	See item 7.b.ii of this table.
		iii. The monthly rolling average of the equilibrium catalyst Ni concentration must not exceed the level established during the performance test	Determining and recording the equilibrium catalyst Ni concentration at least once a week[2]; determining and recording the monthly rolling average of the equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.
	c. Continuous parameter monitoring systems—wet scrubber	i. The average liquid-to-gas ratio must not fall below the operating limit established during the performance test.	See item 7.c.i of this table.
		ii. Except for periods of startup, shutdown and hot standby, the average pressure drop must not fall below the operating limit established in the performance test	See item 7.c.ii of this table.
		iii. The monthly rolling average equilibrium catalyst Ni concentration must not exceed the level established during the performance test	Determining and recording the equilibrium catalyst Ni concentration at least once a week[2]; determining and recording the monthly rolling average of equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.
	d. BLD—fabric filter	i. Increases in relative particulate	See item 7.d of this table.
		ii. The monthly rolling average of the equilibrium catalyst Ni concentration must not exceed the level established during the performance test	Determining and recording the equilibrium catalyst Ni concentration at least once a week[2]; determining and recording the monthly rolling average of the equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.

For each new or existing catalytic cracking unit . . .	**If you use . . .**	**For this operating limit . . .**	**You shall demonstrate continuous compliance by . . .**
9. Option 4: Ni per coke burn-off limit not subject to the NSPS for PM in 40 CFR 60.102	a. Continuous opacity monitoring system	i. The daily average Ni operating value must not exceed the site-specific Ni operating limit established during the performance test	(1) Collecting the hourly average continuous opacity monitoring system data according to §63.1572; collecting the hourly average coke burn rate and hourly average gas flow rate monitoring data according to §63.15721; determining and recording equilibrium catalyst Ni concentration at least once a week^{2}; and determining and recording the hourly average Ni operating value using Equation 12 of §63.1564.
			(2) Determining and recording the 3-hour rolling average Ni operating value and maintaining the 3-hour rolling average Ni operating value below the site-specific Ni operating limit established during the performance test Alternatively, before August 1, 2017, determining and recording the daily average Ni operating value and maintaining the daily average Ni operating value below the site-specific Ni operating limit established during the performance test.
	b. Continuous parameter monitoring systems—electrostatic precipitator	i. The average gas flow rate to the control device must not exceed the level established in the performance test	See item 7.b.i of this table.
		ii. The average voltage and secondary current (or total power input) must not fall below the level established in the performance test	See item 7.b.ii of this table.
		iii. The monthly rolling average equilibrium catalyst Ni concentration must not exceed the level established during the performance test	See item 8.b.iii of this table.
	c. Continuous parameter monitoring systems—wet scrubber	i. The average liquid-to-gas ratio must not fall below the operating limit established during the performance test	See item 7.c.i of this table.
		ii. Except for periods of startup, shutdown and hot standby, the daily average pressure drop must not fall below the operating limit established in the performance test	See item 7.c.ii of this table.

For each new or existing catalytic cracking unit . . .	**If you use . . .**	**For this operating limit . . .**	**You shall demonstrate continuous compliance by . . .**
		iii. The monthly rolling average equilibrium catalyst Ni concentration must not exceed the level established during the performance test	See item 8.c.iii of this table.
	d. BLD—fabric filter	i. See item 2.d of this table	See item 2.d of this table.
		ii. The monthly rolling average of the equilibrium catalyst Ni concentration must not exceed the level established during the performance test	Determining and recording the equilibrium catalyst Ni concentration at least once a week[2]; determining and recording the monthly rolling average of the equilibrium catalyst Ni concentration once each week using the weekly or most recent value; and maintaining the monthly rolling average below the limit established in the performance test.
10. During periods of startup, shutdown, or hot standby	Any control device, if elected	The inlet velocity limit to the primary internal cyclones of the catalytic cracking unit catalyst regenerator in §63.1564(a)(5)(ii)	Meeting the requirements in §63.1564(c)(5).

[1] If applicable, you can use the alternative in §63.1573(a)(1) for gas flow rate instead of a continuous parameter monitoring system if you used the alternative method in the initial performance test.

[2] The equilibrium catalyst Ni concentration must be measured by the procedure, Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure) in appendix A to this subpart; or by EPA Method 6010B, Inductively Coupled Plasma-Atomic Emission Spectrometry, EPA Method 6020, Inductively Coupled Plasma-Mass Spectrometry, EPA Method 7520, Nickel Atomic Absorption, Direct Aspiration, or EPA Method 7521, Nickel Atomic Absorption, Direct Aspiration; or by an alternative to EPA Method 6010B, 6020, 7520, or 7521 satisfactory to the Administrator. The EPA Methods 6010B, 6020, 7520, and 7521 are included in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication SW-846, Revision 5 (April 1998). The SW-846 and Updates (document number 955-001-00000-1) are available for purchase from the Superintendent of Documents, U.S. Government Publishing Office, Washington, DC 20402, (202) 512-1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487-4650. Copies may be inspected at the EPA Docket Center, William Jefferson Clinton (WJC) West Building (Air Docket), Room 3334, 1301 Constitution Ave. NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street NW., Suite 700, Washington, DC. These methods are also available at *http://www.epa.gov/epaoswer/hazwaste/test/main.htm*.

[80 FR 75293, Dec. 1, 2015]

Table 8 to Subpart UUU of Part 63—Organic HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1565(a)(1), you shall meet each emission limitation in the following table that applies to you.

For each new and existing catalytic cracking unit . . .	**You shall meet the following emission limit for each catalyst regenerator vent . . .**
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103 or 60.102a(b)(4)	CO emissions from the catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 parts per million volume (ppmv) (dry basis).

For each new and existing catalytic cracking unit . . .	You shall meet the following emission limit for each catalyst regenerator vent . . .
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4)	a. CO emissions from the catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis). b. If you use a flare to meet the CO limit, then on and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare must meet the requirements for control devices in §63.11(b) and visible emissions must not exceed a total of 5 minutes during any 2 consecutive hours, or the flare must meet the requirements of §63.670.

[80 FR 75299, Dec. 1, 2015]

Table 9 to Subpart UUU of Part 63—Operating Limits for Organic HAP Emissions From Catalytic Cracking Units

As stated in §63.1565(a)(2), you shall meet each operating limit in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	For this type of continuous monitoring system . . .	For this type of control device . . .	You shall meet this operating limit . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103 or 60.102a(b)(4)	Continuous emission monitoring system	Not applicable	Not applicable.
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4)	a. Continuous emission monitoring system.	Not applicable	Not applicable.
	b. Continuous parameter monitoring systems.	i. Thermal incinerator	Maintain the daily average combustion zone temperature above the limit established during the performance test; and maintain the daily average oxygen concentration in the vent stream (percent, dry basis) above the limit established during the performance test.
		ii. Boiler or process heater with a design heat input capacity under 44 MW or a boiler or process heater in which all vent streams are not introduced into the flame zone.	Maintain the daily average combustion zone temperature above the limit established in the performance test.
		iii. Flare	On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it, or the flare must meet the requirements of §63.670.
3. During periods of startup, shutdown or hot standby	Any	Any	Meet the requirements in §63.1565(a)(5).

[80 FR 75299, Dec. 1, 2015]

Table 10 to Subpart UUU of Part 63—Continuous Monitoring Systems for Organic HAP Emissions From Catalytic Cracking Units

As stated in §63.1565(b)(1), you shall meet each requirement in the following table that applies to you.

For each new or existing catalytic cracking unit . . .	**And you use this type of control device for your vent . . .**	**You shall install, operate, and maintain this type of continuous monitoring system . . .**
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103 or 60.102a(b)(4)	Not applicable	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent.
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4)	a. Thermal incinerator	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent; or continuous parameter monitoring systems to measure and record the combustion zone temperature and oxygen content (percent, dry basis) in the incinerator vent stream.
	b. Process heater or boiler with a design heat input capacity under 44 MW or process heater or boiler in which all vent streams are not introduced into the flame zone.	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent; or continuous parameter monitoring systems to measure and record the combustion zone temperature.
	c. Flare	On and after January 30, 2019, the monitoring systems required in §§63.670 and 63.671. Prior to January 30, 2019, monitoring device such as a thermocouple, an ultraviolet beam sensor, or infrared sensor to continuously detect the presence of a pilot flame, or the monitoring systems required in §§63.670 and 63.671.
	d. No control device	Continuous emission monitoring system to measure and record the concentration by volume (dry basis) of CO emissions from each catalyst regenerator vent.
3. During periods of startup, shutdown or hot standby electing to comply with the operating limit in §63.1565(a)(5)(ii)	Any	Continuous parameter monitoring system to measure and record the concentration by volume (dry basis) of oxygen from each catalyst regenerator vent.

[80 FR 75300, Dec. 1, 2015]

Table 11 to Subpart UUU of Part 63—Requirements for Performance Tests for Organic HAP Emissions From Catalytic Cracking Units Not Subject to New Source Performance Standard (NSPS) for Carbon Monoxide (CO)

As stated in §63.1565(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For . . .	**You must . . .**	**Using . . .**	**According to these requirements . . .**
1. Each new or existing catalytic cracking unit catalyst regenerator vent.	a. Select sampling port's location and the number of traverse ports.	Method 1 or 1A in appendix A to part 60 of this chapter.	Sampling sites must be located at the outlet of the control device or the outlet of the regenerator, as applicable, and prior to any releases to the atmosphere.
	b. Determine velocity and volumetric flow rate.	Method 2, 2A, 2D, 2F, or 2G in appendix A to part 60 of this chapter, as applicable.	
	c. Conduct gas molecular weight analysis.	Method 3, 3A, or 3B in appendix A to part 60 of this chapter, as applicable.	
	d. Measure moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.	
2. For each new or existing catalytic cracking unit catalyst regenerator vent if you use a continuous emission monitoring system.	Measure CO emissions	Data from your continuous emission monitoring system.	Collect CO monitoring data for each vent for 24 consecutive operating hours; and reduce the continuous emission monitoring data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period.
3. Each catalytic cracking unit catalyst regenerator vent if you use continuous parameter monitoring systems	a. Measure the CO concentration (dry basis) of emissions exiting the control device	Method 10, 10A, or 10B in appendix A-4 to part 60 of this chapter, as applicable	
	b. Establish each operating limit in Table 9 of this subpart that applies to you	Data from the continuous parameter monitoring systems	
	c. Thermal incinerator combustion zone temperature	Data from the continuous parameter monitoring systems	Collect temperature monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average combustion zone temperature from all the readings.

For . . .	You must . . .	Using . . .	According to these requirements . . .
	d. Thermal incinerator: oxygen, content (percent, dry basis) in the incinerator vent stream	Data from the continuous parameter monitoring systems	Collect oxygen concentration (percent, dry basis) monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average percent excess oxygen concentration from all the readings.
	e. If you use a process heater or boiler with a design heat input capacity under 44 MW or process heater or boiler in which all vent streams are not introduced into the flame zone, establish operating limit for combustion zone temperature	Data from the continuous parameter monitoring systems	Collect the temperature monitoring data every 15 minutes during the entire period of the CO initial performance test; and determine and record the minimum hourly average combustion zone temperature from all the readings.
	f. If you use a flare, conduct visible emission observations	Method 22 (40 CFR part 60, appendix A-7)	On and after January 30, 2019, meet the requirements of §63.670. Prior to January 30, 2019, maintain a 2-hour observation period; and record the presence of a flame at the pilot light over the full period of the test or meet the requirements of §63.670.
	g. If you use a flare, determine that the flare meets the requirements for net heating value of the gas being combusted and exit velocity	40 CFR 63.11(b)(6) through (8)	On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare must meet the control device requirements in §63.11(b) or the requirements of §63.670.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6948, Feb. 9, 2005; 80 FR 75301, Dec. 1, 2015]

Table 12 to Subpart UUU of Part 63—Initial Compliance With Organic HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1565(b)(4), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103, 60.100(e), or 60.102a(b)(4)	CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis)	You have already conducted a performance test to demonstrate initial compliance with the NSPS and the measured CO emissions are less than or equal to 500 ppm (dry basis). As part of the Notification of Compliance Status, you must certify that your vent meets the CO limit. You are not required to conduct another performance test to demonstrate initial compliance. You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in §63.1572. You are not required to conduct another performance evaluation to demonstrate initial compliance.

For each new and existing catalytic cracking unit . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
2. Not subject to the NSPS for CO in 40 CFR 60.103 60.102a(b)(4)	a. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis)	i. If you use a continuous parameter monitoring system, the average CO emissions measured by Method 10 over the period of the initial performance test are less than or equal to 500 ppmv (dry basis).
		ii. If you use a continuous emission monitoring system, the hourly average CO emissions over the 24-hour period for the initial performance test are not more than 500 ppmv (dry basis); and your performance evaluation shows your continuous emission monitoring system meets the applicable requirements in §63.1572.
	b. If you use a flare, visible emissions must not exceed a total of 5 minutes during any 2 operating hours	On and after January 30, 2019, the flare meets the requirements of §63.670. Prior to January 30, 2019, visible emissions, measured by Method 22 during the 2-hour observation period during the initial performance test, are no higher than 5 minutes, or the flare meets the requirements of §63.670.

[80 FR 75302, Dec. 1, 2015]

Table 13 to Subpart UUU of Part 63—Continuous Compliance With Organic HAP Emission Limits for Catalytic Cracking Units

As stated in §63.1565(c)(1), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic cracking unit . . .	Subject to this emission limit for your catalyst regenerator vent . . .	If you must . . .	You shall demonstrate continuous compliance by . . .
1. Subject to the NSPS for carbon monoxide (CO) in 40 CFR 60.103, 60.100(e), or 60.102a(b)(4)	CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	Continuous emission monitoring system	Collecting the hourly average CO monitoring data according to §63.1572; and maintaining the hourly average CO concentration at or below 500 ppmv (dry basis).
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4)	a. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	Continuous emission monitoring system.	Same as item 1.
	b. CO emissions from your catalyst regenerator vent or CO boiler serving the catalytic cracking unit must not exceed 500 ppmv (dry basis).	Continuous parameter monitoring system.	Maintaining the hourly average CO concentration below 500 ppmv (dry basis).
	c. Visible emissions from a flare must not exceed a total of 5 minutes during any 2-hour period.	Control device-flare	On and after January 30, 2019, meeting the requirements of §63.670. Prior to January 30, 2019, maintaining visible emissions below a total of 5 minutes during any 2-hour operating period, or meeting the requirements of §63.670.

[80 FR 75302, Dec. 1, 2015]

Table 14 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Organic HAP Emissions From Catalytic Cracking Units

As stated in §63.1565(c)(1), you shall meet each requirement in the following table that applies to you.

For each new existing catalytic cracking unit . . .	**If you use . . .**	**For this operating limit . . .**	**You shall demonstrate continuous compliance by . . .**
1. Subject to NSPS for carbon monoxide (CO) in 40 CFR 60.103, 60.100(e), 60.102a(b)(4)	Continuous emission monitoring system.	Not applicable	Complying with Table 13 of this subpart, item 1.
2. Not subject to the NSPS for CO in 40 CFR 60.103 or 60.102a(b)(4)	a. Continuous emission monitoring system	Not applicable	Complying with Table 13 of this subpart, item 2.a.
	b. Continuous parameter monitoring systems—thermal incinerator.	i. The daily average combustion zone temperature must not fall below the level established during the performance test.	Collecting the hourly and daily average temperature monitoring data according to §63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test.
		ii. The daily average oxygen concentration in the vent stream (percent, dry basis) must not fall below the level established during the performance test.	Collecting the hourly and daily average oxygen concentration monitoring data according to §63.1572; and maintaining the daily average oxygen concentration above the limit established during the performance test.
	c. Continuous parameter monitoring systems—boiler or process heater with a design heat input capacity under 44 MW or boiler or process heater in which all vent streams are not introduced into the flame zone.	The daily combustion zone temperature must not fall below the level established in the performance test.	Collecting the average hourly and daily temperature monitoring data according to §63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test.
	d. Continuous parameter monitoring system—flare.	The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it.	On and after January 30, 2019, meeting the requirements of §63.670. Prior to January 30, 2019, collecting the flare monitoring data according to §63.1572 and recording for each 1-hour period whether the monitor was continuously operating and the pilot light was continuously present during each 1-hour period, or meeting the requirements of §63.670.

For each new existing catalytic cracking unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
3. During periods of startup, shutdown or hot standby electing to comply with the operating limit in §63.1565(a)(5)(ii).	Any control device	The oxygen concentration limit in §63.1565(a)(5)(ii)	Collecting the hourly average oxygen concentration monitoring data according to §63.1572 and maintaining the hourly average oxygen concentration at or above 1 volume percent (dry basis).

[80 FR 75303, Dec. 1, 2015]

Table 15 to Subpart UUU of Part 63—Organic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1566(a)(1), you shall meet each emission limitation in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit . . .	You shall meet this emission limit during initial catalyst depressuring and catalyst purging operations . . .
1. Option 1	On and after January 30, 2019, vent emissions to a flare that meets the requirements of §63.670. Prior to January 30, 2019, vent emissions to a flare that meets the requirements for control devices in §63.11(b) and visible emissions from a flare must not exceed a total of 5 minutes during any 2-hour operating period, or vent emissions to a flare that meets the requirements of §63.670.
2. Option 2	Reduce uncontrolled emissions of total organic compounds (TOC) or nonmethane TOC from your process vent by 98 percent by weight using a control device or to a concentration of 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent. If you vent emissions to a boiler or process heater to comply with the percent reduction or concentration emission limitation, the vent stream must be introduced into the flame zone, or any other location that will achieve the percent reduction or concentration standard.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6951, Feb. 9, 2005; 80 FR 75304, Dec. 1, 2015]

Table 16 to Subpart UUU of Part 63—Operating Limits for Organic HAP Emissions From Catalytic Reforming Units

As stated in §63.1566(a)(2), you shall meet each operating limit in the following table that applies to you.

For each new or existing catalytic reforming unit . . .	For this type of control device . . .	You shall meet this operating limit during initial catalyst depressuring and purging operations. . .
1. Option 1: Vent to flare	Flare	On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it, or the flare must meet the requirements of §63.670.

For each new or existing catalytic reforming unit . . .	For this type of control device . . .	You shall meet this operating limit during initial catalyst depressuring and purging operations. . .
2. Option 2: Percent reduction or concentration limit	a. Thermal incinerator, boiler or process heater with a design heat input capacity under 44 MW, or boiler or process heater in which all vent streams are not introduced into the flame zone	The daily average combustion zone temperature must not fall below the limit established during the performance test.
	b. No control device	Operate at all times according to your operation, maintenance, and monitoring plan regarding minimum catalyst purging conditions that must be met prior to allowing uncontrolled purge releases.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6951, Feb. 9, 2005; 80 FR 75304, Dec. 1, 2015]

Table 17 to Subpart UUU of Part 63—Continuous Monitoring Systems for Organic HAP Emissions From Catalytic Reforming Units

As stated in §63.1566(b)(1), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit . . .	If you use this type of control device . . .	You shall install and operate this type of continuous monitoring system . . .
1. Option 1: Vent to a flare	Flare	On and after January 30, 2019, the monitoring systems required in §§63.670 and 63.671. Prior to January 30, 2019, monitoring device such as a thermocouple, an ultraviolet beam sensor, or infrared sensor to continuously detect the presence of a pilot flame, or the monitoring systems required in §§63.670 and 63.671.
2. Option 2: percent reduction or concentration limit.	Thermal incinerator, process heater or boiler with a design heat input capacity under 44 MW, or process heater or boiler in which all vent streams are not introduced into the flame zone	Continuous parameter monitoring systems to measure and record the combustion zone temperature.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6952, Feb. 9, 2005; 80 FR 75304, Dec. 1, 2015]

Table 18 to Subpart UUU of Part 63—Requirements for Performance Tests for Organic HAP Emissions From Catalytic Reforming Units

As stated in §63.1566(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For each new or exiting catalytic reforming unit . . .	You must . . .	Using . . .	According to these requirements . . .
1. Option 1: Vent to a flare	a. Conduct visible emission observations	Method 22 (40 CFR part 60, appendix A-7)	On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, 2-hour observation period. Record the presence of a flame at the pilot light over the full period of the test, or the requirements of §63.670.
	b. Determine that the flare meets the requirements for net heating value of the gas being combusted and exit velocity	40 CFR 63.11(b)(6) through (8)	On and after January 30, 2019, the flare must meet the requirements of §63.670. Prior to January 30, 2019, the flare must meet the control device requirements in §63.11(b) or the requirements of §63.670.
2. Option 2: Percent reduction or concentration limit	a. Select sampling site	Method 1 or 1A (40 CFR part 60, appendix A). No traverse site selection method is needed for vents smaller than 0.10 meter in diameter.	Sampling sites must be located at the inlet (if you elect the emission reduction standard) and outlet of the control device and prior to any releases to the atmosphere.
	b. Measure gas volumetric flow rate	Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A), as applicable	
	c. Measure TOC concentration (for percent reduction standard)	Method 25 (40 part 60, appendix A) to measure nonmethane TOC concentration (in carbon equivalents) at inlet and outlet of the control device. If the nonmethane TOC outlet concentration is expected to be less than 50 ppm (as carbon), you can use Method 25A to measure TOC concentration (as hexane) at the inlet and the outlet of the control device. If you use Method 25A, you may use Method 18 (40 CFR part 60, appendix A) to measure the methane concentration to determine the nonmethane TOC concentration	Take either an integrated sample or four grab samples during each run. If you use a grab sampling technique, take the samples at approximately equal intervals in time, such as 15-minute intervals during the run.

For each new or exiting catalytic reforming unit . . .	**You must . . .**	**Using . . .**	**According to these requirements . . .**
	d. Calculate TOC or nonmethane TOC emission rate and mass emission reduction		Calculate emission rate by Equation 1 of §63.1566 (if you use Method 25) or Equation 2 of §63.1566 (if you use Method 25A). Calculate mass emission reduction by Equation 3 of §63.1566.
	e. For concentration standard, measure TOC concentration. (Optional: Measure methane concentration.)	Method 25A (40 CFR part 60, appendix A) to measure TOC concentration (as hexane) at the outlet of the control device. You may elect to use Method 18 (40 CFR part 60, appendix A) to measure the methane concentration	
	f. Determine oxygen content in the gas stream at the outlet of the control device	Method 3A or 3B (40 CFR part 60, appendix A), as applicable	
	g. Calculate the TOC or nonmethane TOC concentration corrected for oxygen content (for concentration standard)	Equation 4 of §63.1566	
	h. Establish each operating limit in Table 16 of this subpart that applies to you for a thermal incinerator, or process heater or boiler with a design heat input capacity under 44 MW, or process heater or boiler in which all vent streams are not introduced into flame zone	Data from the continuous parameter monitoring systems	Collect the temperature monitoring data every 15 minutes during the entire period of the initial TOC performance test. Determine and record the minimum hourly average combustion zone temperature.
	i. If you do not use a control device, document the purging conditions used prior to testing following the minimum requirements in the operation, maintenance, and monitoring plan.	Data from monitoring systems as identified in the operation, maintenance, and monitoring plan	Procedures in the operation, maintenance, and monitoring plan.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6952, Feb. 9, 2005; 80 FR 75305, Dec. 1, 2015]

Table 19 to Subpart UUU of Part 63—Initial Compliance With Organic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1566(b)(7), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
Option 1	Visible emissions from a flare must not exceed a total of 5 minutes during any 2 consecutive hours	On and after January 30, 2019, the flare meets the requirements of §63.670. Prior to January 30, 2019, visible emissions, measured using Method 22 over the 2-hour observation period of the performance test, do not exceed a total of 5 minutes, or the flare meets the requirements of §63.670.
Option 2	Reduce uncontrolled emissions of total organic compounds (TOC) or nonmethane TOC from your process vent by 98 percent by weight using a control device or to a concentration of 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent	The mass emission reduction of nonmethane TOC measured by Method 25 over the period of the performance test is at least 98 percent by weight as calculated using Equations 1 and 3 of §63.1566; or the mass emission reduction of TOC measured by Method 25A (or nonmethane TOC measured by Methods 25A and 18) over the period of the performance test is at least 98 percent by weight as calculated using Equations 2 and 3 of §63.1566; or the TOC concentration measured by Method 25A (or the nonmethane TOC concentration measured by Methods 25A and 18) over the period of the performance test does not exceed 20 ppmv (dry basis as hexane) corrected to 3 percent oxygen as calculated using Equation 4 of §63.1566.

[70 FR 6953, Feb. 9, 2005, as amended at 80 FR 75305, Dec. 1, 2015]

Table 20 to Subpart UUU of Part 63—Continuous Compliance With Organic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1566(c)(1), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit . . .	For this emission limit . . .	You shall demonstrate continuous compliance during initial catalyst depressuring and catalyst purging operations by . . .
1. Option 1	Vent emissions from your process vent to a flare	On and after January 30, 2019, meeting the requirements of §63.670. Prior to January 30, 2019, maintaining visible emissions from a flare below a total of 5 minutes during any 2 consecutive hours, or meeting the requirements of §63.670.

For each applicable process vent for a new or existing catalytic reforming unit . . .	For this emission limit . . .	You shall demonstrate continuous compliance during initial catalyst depressuring and catalyst purging operations by . . .
2. Option 2	Reduce uncontrolled emissions of total organic compounds (TOC) or nonmethane TOC from your process vent by 98 percent by weight using a control device or to a concentration of 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent.	Maintaining a 98 percent by weight emission reduction of TOC or nonmethane TOC; or maintaining a TOC or nonmethane TOC concentration of not more than 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen, whichever is less stringent.

[70 FR 6954, Feb. 9, 2005, as amended at 80 FR 75305, Dec. 1, 2015]

Table 21 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Organic HAP Emissions From Catalytic Reforming Units

As stated in §63.1566(c)(1), you shall meet each requirement in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit . . .	If you use . . .	For this operating limit . . .	You shall demonstrate continuous compliance during initial catalyst depressuring and purging operations by . . .
1. Option 1	Flare	The flare pilot light must be present at all times and the flare must be operating at all times that emissions may be vented to it	On and after January 30, 2019, meeting the requirements of §63.670. Prior to January 30, 2019, collecting flare monitoring data according to §63.1572 and recording for each 1-hour period whether the monitor was continuously operating and the pilot light was continuously present during each 1-hour period, or meeting the requirements of §63.670.
2. Option 2	a. Thermal incinerator boiler or process heater with a design input capacity under 44 MW or boiler or process heater in which not all vent streams are not introduced into the flame zone	Maintain the daily average combustion zone temperature above the limit established during the performance test	Collecting, the hourly and daily temperature monitoring data according to §63.1572; and maintaining the daily average combustion zone temperature above the limit established during the performance test.
	b. No control device	Operate at all times according to your operation, maintenance, and monitoring plan regarding minimum purging conditions that must be met prior to allowing uncontrolled purge releases	Recording information to document compliance with the procedures in your operation, maintenance, and monitoring plan.

[70 FR 6954, Feb. 9, 2005, as amended at 80 FR 75306, Dec. 1, 2015]

Table 22 to Subpart UUU of Part 63—Inorganic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1567(a)(1), you shall meet each emission limitation in the following table that applies to you.

For . . .	You shall meet this emission limit for each applicable catalytic reforming unit process vent during coke burn-off and catalyst rejuvenation . . .
1. Each existing semi-regenerative catalytic reforming unit	Reduce uncontrolled emissions of hydrogen chloride (HCl) by 92 percent by weight or to a concentration of 30 ppmv (dry basis), corrected to 3 percent oxygen.
2. Each existing cyclic or continuous catalytic reforming unit	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.
3. Each new semi-regenerative, cyclic, or continuous catalytic reforming unit	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen.

[70 FR 6955, Feb. 9, 2005, as amended at 80 FR 75306, Dec. 1, 2015]

Table 23 to Subpart UUU of Part 63—Operating Limits for Inorganic HAP Emission Limitations for Catalytic Reforming Units

As stated in §63.1567(a)(2), you shall meet each operating limit in the following table that applies to you.

For each applicable process vent for a new or existing catalytic reforming unit with this type of control device . . .	You shall meet this operating limit during coke burn-off and catalyst rejuvenation . . .
1. Wet scrubber	The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber must not fall below the limit established during the performance test; and the daily average liquid-to-gas ratio must not fall below the limit established during the performance test.
2. Internal scrubbing system or no control device (*e.g.*, hot regen system) meeting outlet HCl concentration limit.	The daily average HCl concentration in the catalyst regenerator exhaust gas must not exceed the limit established during the performance test.
3. Internal scrubbing system meeting HCl percent reduction standard.	The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system must not fall below the limit established during the performance test; and the daily average liquid-to-gas ratio must not fall below the limit established during the performance test.
4. Fixed-bed gas-solid adsorption system	The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test; and the HCl concentration in the adsorption system exhaust gas must not exceed the limit established during the performance test.
5. Moving-bed gas-solid adsorption system (*e.g.*, Chlorsorb^{TM} System).	The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test; and the weekly average chloride level on the sorbent entering the adsorption system must not exceed the design or manufacturer's recommended limit (1.35 weight percent for the Chlorsorb^{TM} System); and the weekly average chloride level on the sorbent leaving the adsorption system must not exceed the design or manufacturer's recommended limit (1.8 weight percent for the Chlorsorb^{TM} System).

[70 FR 6955, Feb. 9, 2005]

Table 24 to Subpart UUU of Part 63—Continuous Monitoring Systems for Inorganic HAP Emissions From Catalytic Reforming Units

As stated in §63.1567(b)(1), you shall meet each requirement in the following table that applies to you.

If you use this type of control device for your vent . . .	You shall install and operate this type of continuous monitoring system . . .
1. Wet scrubber	Continuous parameter monitoring system to measure and record the total water (or scrubbing liquid) flow rate entering the scrubber during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record gas flow rate entering or exiting the scrubber during coke burn-off and catalyst rejuvenation[1]; and continuous parameter monitoring system to measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation.[2]
2. Internal scrubbing system or no control device (*e.g.,* hot regen system) to meet HCl outlet concentration limit	Colormetric tube sampling system to measure the HCl concentration in the catalyst regenerator exhaust gas during coke burn-off and catalyst rejuvenation. The colormetric tube sampling system must meet the requirements in Table 41 of this subpart.
3. Internal scrubbing system to meet HCl percent reduction standard	Continuous parameter monitoring system to measure and record the gas flow rate entering or exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record the total water (or scrubbing liquid) flow rate entering the internal scrubbing system during coke burn-off and catalyst rejuvenation; and continuous parameter monitoring system to measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation.[2]
4. Fixed-bed gas-solid adsorption system	Continuous parameter monitoring system to measure and record the temperature of the gas entering or exiting the adsorption system during coke burn-off and catalyst rejuvenation; and colormetric tube sampling system to measure the gaseous HCl concentration in the adsorption system exhaust and at a point within the absorbent bed not to exceed 90 percent of the total length of the absorbent bed during coke burn-off and catalyst rejuvenation. The colormetric tube sampling system must meet the requirements in Table 41 of this subpart.
5. Moving-bed gas-solid adsorption system (e.g., Chlorsorb™ System).	Continuous parameter monitoring system to measure and record the temperature of the gas entering or exiting the adsorption system during coke burn-off and catalyst rejuvenation.

[1] If applicable, you can use the alternative in §63.1573 (a)(1) instead of a continuous parameter monitoring system for gas flow rate or instead of a continuous parameter monitoring system for the cumulative volume of gas.

[2] If applicable, you can use the alternative in §63.1573(c)(1) instead of a continuous parameter monitoring system for pH of the water (or scrubbing liquid) or the alternative in §63.1573(c)(2) instead of a continuous parameter monitoring system for alkalinity of the water (or scrubbing liquid).

[70 FR 6956, Feb. 9, 2005, as amended at 80 FR 75306, Dec. 1, 2015]

Table 25 to Subpart UUU of Part 63—Requirements for Performance Tests for Inorganic HAP Emissions From Catalytic Reforming Units

As stated in §63.1567(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic reforming unit using . . .	You shall . . .	Using . . .	According to these requirements . . .
1. Any or no control system	a. Select sampling port location(s) and the number of traverse points	Method 1 or 1A (40 CFR part 60, appendix A), as applicable.	(1) If you operate a control device and you elect to meet an applicable HCl percent reduction standard, sampling sites must be located at the inlet of the control device or internal scrubbing system and at the outlet of the control device or internal scrubber system prior to any release to the atmosphere. For a series of fixed-bed systems, the outlet sampling site should be located at the outlet of the first fixed-bed, prior to entering the second fixed-bed in the series.
			(2) If you elect to meet an applicable HCl outlet concentration limit, locate sampling sites at the outlet of the control device or internal scrubber system prior to any release to the atmosphere. For a series of fixed-bed systems, the outlet sampling site should be located at the outlet of the first fixed-bed, prior to entering the second fixed-bed in the series. If there is no control device, locate sampling sites at the outlet of the catalyst regenerator prior to any release to the atmosphere.
	b. Determine velocity and volumetric flow rate.	Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A), as applicable.	
	c. Conduct gas molecular weight analysis.	Method 3, 3A, or 3B (40 CFR part 60, appendix A), as applicable	
	d. Measure moisture content of the stack gas	Method 4 (40 CFR part 60, appendix A)	
	e. Measure the HCl concentration at the selected sampling locations	Method 26 or 26A (40 CFR part 60, appendix A). If your control device is a wet scrubber or internal scrubbing system, you must use Method 26A	(1) For semi-regenerative and cyclic regeneration units, conduct the test during the coke burn-off and catalyst rejuvenation cycle, but collect no samples during the first hour or the last 6 hours of the cycle (for semi- regenerative units) or during the first hour or the last 2 hours of the cycle (for cyclic regeneration units). For continuous regeneration units, the test should be conducted no sooner than 3 days after process unit or control system start up.

For each new and existing catalytic reforming unit using . . .	You shall . . .	Using . . .	According to these requirements . . .
			(2) Determine and record the HCl concentration corrected to 3 percent oxygen (using Equation 1 of §63.1567) for each sampling location for each test run.
			(3) Determine and record the percent emission reduction, if applicable, using Equation 3 of §63.1567 for each test run.
			(4) Determine and record the average HCl concentration (corrected to 3 percent oxygen) and the average percent emission reduction, if applicable, for the overall source test from the recorded test run values.
2. Wet scrubber	a. Establish operating limit for pH level or alkalinity	i. Data from continuous parameter monitoring systems	Measure and record the pH or alkalinity of the water (or scrubbing liquid) exiting scrubber every 15 minutes during the entire period of the performance test. Determine and record the minimum hourly average pH or alkalinity level from the recorded values.
		ii. Alternative pH procedure in §63.1573(b)(1)	Measure and record the pH of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation using pH strips at least three times during each test run. Determine and record the average pH level for each test run. Determine and record the minimum test run average pH level.
		iii. Alternative alkalinity method in §63.1573(c)(2)	Measure and record the alkalinity of the water (or scrubbing liquid) exiting the scrubber during coke burn-off and catalyst rejuvenation using discrete titration at least three times during each test run. Determine and record the average alkalinity level for each test run. Determine and record the minimum test run average alkalinity level.
	b. Establish operating limit for liquid-to-gas ratio.	i. Data from continuous parameter monitoring systems	Measure and record the gas flow rate entering or exiting the scrubber and the total water (or scrubbing liquid) flow rate entering the scrubber every 15 minutes during the entire period of the performance test. Determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate. Determine and record the minimum liquid-to-gas ratio from the recorded, paired values.

For each new and existing catalytic reforming unit using . . .	**You shall . . .**	**Using . . .**	**According to these requirements . . .**
		ii. Alternative procedure for gas flow rate in §63.1573(a)(1)	Collect air flow rate monitoring data or determine the air flow rate using control room instruments every 15 minutes during the entire period of the initial performance test. Determine and record the hourly average rate of all the readings. Determine and record the maximum gas flow rate using Equation 1 of §63.1573.
3. Internal scrubbing system or no control device (e.g., hot regen system) meeting HCl outlet concentration limit.	Establish operating limit for HCl concentration.	Data from continuous parameter monitoring system.	Measure and record the HCl concentration in the catalyst regenerator exhaust gas using the colormetric tube sampling system at least three times during each test run. Determine and record the average HCl concentration for each test run. Determine and record the average HCl concentration for the overall source test from the recorded test run averages. Determine and record the operating limit for HCl concentration using Equation 4 of §63.1567.
4. Internal scrubbing system meeting HCl percent reduction standard	a. Establish operating limit for pH level or alkalinity	i. Data from continuous parameter monitoring system	Measure and record the pH alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system every 15 minutes during the entire period of the performance test. Determine and record the minimum hourly average pH or alkalinity level from the recorded values.
		ii. Alternative pH method in §63.1573(c)(1)	Measure and in record pH of the water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation using pH strips at least three times during each test run. Determine and record the average pH level for each test run. Determine and record the minimum test run average pH level.
		iii. Alternative alkalinity method in §63.1573(c)(2)	Measure and record the alkalinity water (or scrubbing liquid) exiting the internal scrubbing system during coke burn-off and catalyst rejuvenation using discrete titration at least three times during each test run. Determine and record the average alkalinity level for each test run. Determine and record the minimum test run average alkalinity level.

For each new and existing catalytic reforming unit using . . .	You shall . . .	Using . . .	According to these requirements . . .
	b. Establish operating limit for liquid-to-gas ratio	Data from continuous parameter monitoring systems	Measure and record the gas entering or exiting the internal scrubbing system and the total water (or scrubbing liquid) flow rate entering the internal scrubbing system every 15 minutes during the entire period of the performance test. Determine and record the hourly average gas flow rate and total water (or scrubbing liquid) flow rate. Determine and record the minimum liquid-to-gas ratio from the recorded, paired values.
5. Fixed-bed gas-solid adsorption system. Gas-solid	a. Establish operating limit for temperature	Data from continuous parameter monitoring system	Measure and record the temperature of gas entering or exiting the adsorption system every 15 minutes. Determine and record the maximum hourly average temperature.
	b. Establish operating limit for HCl concentration	i. Data from continuous parameter monitoring systems	(1) Measure and record the HCl concentration in the exhaust gas from the fixed-bed adsorption system using the colormetric tube sampling system at least three times during each test run. Determine and record the average HCl concentration for each test run. Determine and record the average HCl concentration for the overall source test from the recorded test run averages.
			(2) If you elect to comply with the HCl outlet concentration limit (Option 2), determine and record the operating limit for HCl concentration using Equation 4 of §63.1567. If you elect to comply with the HCl percent reduction standard (Option 1), determine and record the operating limit for HCl concentration using Equation 5 of §63.1567.
6. Moving-bed gas-solid adsorption system (e.g., Chlorsorb^{TM} System)	a. Establish operating limit for temperature	Data from continuous parameter monitoring systems.	Measure and record the temperature of gas entering or exiting the adsorption system every 15 minutes. Determine and record the maximum hourly average temperature.
	b. Measure the chloride level on the sorbent entering and exiting the adsorption system.	Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure) in appendix A to subpart UUU; or EPA Method 5050 combined either with EPA Method 9056, or with EPA Method 9253; or EPA Method 9212 with the soil extraction procedures listed within the method.[1]	Measure and record the chloride concentration of the sorbent material entering and exiting the adsorption system at least three times during each test run. Determine and record the average weight percent chloride concentration of the sorbent entering the adsorption system for each test run. Determine and record the average weight percent chloride concentration of the sorbent exiting the adsorption system for each test run.

[1] The EPA Methods 5050, 9056, 9212 and 9253 are included in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW-846, Revision 5 (April 1998). The SW-846 and Updates (document number 955-001-00000-1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512-1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487-4650. Copies may be inspected at the EPA Docket Center, William Jefferson Clinton (WJC) West Building (Air Docket), Room 3334, 1301 Constitution Ave. NW., Washington, DC; or at the Office of the Federal Register, 800 North Capitol Street NW., Suite 700, Washington, DC. These methods are also available at *http://www.epa.gov/epaoswer/hazwaste/test/main.htm*.

[70 FR 6956, Feb. 9, 2005, as amended at 80 FR 75307, Dec. 1, 2015]

Table 26 to Subpart UUU of Part 63—Initial Compliance With Inorganic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1567(b)(4), you shall meet each requirement in the following table that applies to you.

For . . .	**For the following emission limit . . .**	**You have demonstrated initial compliance if . . .**
1. Each existing semi-regenerative catalytic reforming unit	Reduce uncontrolled emissions of HCl by 92 percent by weight or to a concentration of 30 ppmv, (dry basis), corrected to 3 percent oxygen.	Average emissions HCl measured using Method 26 or 26A, as applicable, over the period of the performance test, are reduced by 92 percent or to a concentration less than or equal to 30 ppmv (dry basis) corrected to 3 percent oxygen.
2. Each existing cyclic or continuous catalytic reforming unit and each new semi-regenerative, cyclic, or continuous catalytic reforming unit.	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen	Average emissions of HCl measured using Method 26 or 26A, as applicable, over the period of the performance test, are reduced by 97 percent or to a concentration less than or equal to 10 ppmv (dry basis) corrected to 3 percent oxygen.

[70 FR 6959, Feb. 9, 2005]

Table 27 to Subpart UUU of Part 63—Continuous Compliance With Inorganic HAP Emission Limits for Catalytic Reforming Units

As stated in §63.1567(c)(1), you shall meet each requirement in the following table that applies to you.

For . . .	**For this emission limit . . .**	**You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by . . .**
1. Each existing semi-regenerative catalytic reforming unit	Reduce uncontrolled emissions of HCl by 92 percent by weight or to a concentration of 30 ppmv (dry basis), corrected to 3 percent oxygen.	Maintaining a 92 percent HCl emission reduction or an HCl concentration no more than 30 ppmv (dry basis), corrected to 3 percent oxygen.
2. Each existing cyclic or continuous catalytic reforming unit	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen	Maintaining a 97 percent HCl control efficiency or an HCl concentration no more than 10 ppmv (dry basis), corrected to 3 percent oxygen.
3. Each new semi-regenerative, cyclic, or continuous catalytic reforming unit	Reduce uncontrolled emissions of HCl by 97 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen	Maintaining a 97 percent HCl control efficiency or an HCl concentration no more than 10 ppmv (dry basis), corrected to 3 percent oxygen.

[70 FR 6960, Feb. 9, 2005]

Table 28 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for Inorganic HAP Emissions From Catalytic Reforming Units

As stated in §63.1567(c)(1), you shall meet each requirement in the following table that applies to you.

For each new and existing catalytic reforming unit using this type of control device or system . . .	For this operating limit . . .	You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by . . .
1. Wet scrubber	a. The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the scrubber must not fall below the level established during the performance test	Collecting the hourly and daily average pH or alkalinity monitoring data according to §63.1572[1]; and maintaining the daily average pH or alkalinity above the operating limit established during the performance test.
	b. The daily average liquid-to-gas ratio must not fall below the level established during the performance test	Collecting the hourly average gas flow rate[2] and total water (or scrubbing liquid) flow rate monitoring data according to §63.1572; and determining and recording the hourly average liquid-to-gas ratio; and determining and recording the daily average liquid-to-gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test.
2. Internal scrubbing system or no control device (e.g., hot regen system) meeting HCl concentration limit	The daily average HCl concentration in the catalyst regenerator exhaust gas must not exceed the limit established during the performance test	Measuring and recording the HCl concentration at least 4 times during a regeneration cycle (equally spaced in time) or every 4 hours, whichever is more frequent, using a colormetric tube sampling system; calculating the daily average HCl concentration as an arithmetic average of all samples collected in each 24-hour period from the start of the coke burn-off cycle or for the entire duration of the coke burn-off cycle if the coke burn-off cycle is less than 24 hours; and maintaining the daily average HCl concentration below the applicable operating limit.
3. Internal scrubbing system meeting percent HCl reduction standard	a. The daily average pH or alkalinity of the water (or scrubbing liquid) exiting the internal scrubbing system must not fall below the limit established during the performance test	Collecting the hourly and daily average pH or alkalinity monitoring data according to §63.1572[1] and maintaining the daily average pH or alkalinity above the operating limit established during the performance test.
	b. The daily average liquid-to-gas ratio must not fall below the level established during the performance test	Collecting the hourly average gas flow rate[2] and total water (or scrubbing liquid) flow rate monitoring data according to §63.1572; and determining and recording the hourly average liquid-to-gas ratio; and determining and recording the daily average liquid-to-gas ratio; and maintaining the daily average liquid-to-gas ratio above the limit established during the performance test.
4. Fixed-bed gas-solid adsorption systems	a. The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test	Collecting the hourly and daily average temperature monitoring data according to §63.1572; and maintaining the daily average temperature below the operating limit established during the performance test.

For each new and existing catalytic reforming unit using this type of control device or system . . .	**For this operating limit . . .**	**You shall demonstrate continuous compliance during coke burn-off and catalyst rejuvenation by . . .**
	b. The HCl concentration in the exhaust gas from the fixed-bed gas-solid adsorption system must not exceed the limit established during the performance test	Measuring and recording the concentration of HCl weekly or during each regeneration cycle, whichever is less frequent, using a colormetric tube sampling system at a point within the adsorbent bed not to exceed 90 percent of the total length of the adsorption bed during coke-burn-off and catalyst rejuvenation; implementing procedures in the operating and maintenance plan if the HCl concentration at the sampling location within the adsorption bed exceeds the operating limit; and maintaining the HCl concentration in the gas from the adsorption system below the applicable operating limit.
5. Moving-bed gas-solid adsorption system (*e.g.,* ChlorsorbTM System)	a. The daily average temperature of the gas entering or exiting the adsorption system must not exceed the limit established during the performance test	Collecting the hourly and daily average temperature monitoring data according to §63.1572; and maintaining the daily average temperature below the operating limit established during the performance test.
	b. The weekly average chloride level on the sorbent entering the adsorption system must not exceed the design or manufacturer's recommended limit (1.35 weight percent for the Chlorsorb^{TM} System)	Collecting samples of the sorbent exiting the adsorption system three times per week (on non-consecutive days); and analyzing the samples for total chloride[3]; and determining and recording the weekly average chloride concentration; and maintaining the chloride concentration below the design or manufacturer's recommended limit (1.35 weight percent for the Chlorsorb^{TM} System).
	c. The weekly average chloride level on the sorbent exiting the adsorption system must not exceed the design or manufacturer's recommended limit (1.8 weight percent for the Chlorsorb^{TM} System)	Collecting samples of the sorbent exiting the adsorption system three times per week (on non-consecutive days); and analyzing the samples for total chloride concentration; and determining and recording the weekly average chloride concentration; and maintaining the chloride concentration below the design or manufacturer's recommended limit (1.8 weight percent Chlorsorb^{TM} System).

[1] If applicable, you can use either alternative in §63.1573(c) instead of a continuous parameter monitoring system for pH or alkalinity if you used the alternative method in the initial performance test.

[2] If applicable, you can use the alternative in §63.1573(a)(1) instead of a continuous parameter monitoring system for the gas flow rate or cumulative volume of gas entering or exiting the system if you used the alternative method in the initial performance test.

[3] The total chloride concentration of the sorbent material must be measured by the procedure, “Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure)” in appendix A to this subpart; or by using EPA Method 5050, Bomb Preparation Method for Solid Waste, combined either with EPA Method 9056, Determination of Inorganic Anions by Ion Chromatography, or with EPA Method 9253, Chloride (Titrimetric, Silver Nitrate); or by using EPA Method 9212, Potentiometric Determination of Chloride in Aqueous Samples with Ion-Selective Electrode, and using the soil extraction procedures listed within the method. The EPA Methods 5050, 9056, 9212 and 9253 are included in “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” EPA Publication SW-846, Revision 5 (April 1998). The SW-846 and Updates (document number 955-001-00000-1) are available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512-1800; and from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 487-4650. Copies may be inspected at the EPA Docket Center, William Jefferson Clinton (WJC) West Building, (Air Docket), Room 3334, 1301 Constitution Ave. NW., Washington, DC; or at the Office

of the Federal Register, 800 North Capitol Street NW., Suite 700, Washington, DC. These methods are also available at *http://www.epa.gov/epaoswer/hazwaste/test/main.htm*.

[70 FR 6954, Feb. 9, 2005, as amended at 80 FR 75308, Dec. 1, 2015]

Table 29 to Subpart UUU of Part 63—HAP Emission Limits for Sulfur Recovery Units

As stated in §63.1568(a)(1), you shall meet each emission limitation in the following table that applies to you.

For . . .	**You shall meet this emission limit for each process vent . . .**
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 long tons per day (LTD) and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	a. 250 ppmv (dry basis) of sulfur dioxide (SO_2) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation control system or if you use a reduction control system followed by incineration.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration.
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation control system or if you use a reduction control system followed by incineration.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration.
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	300 ppmv of total reduced sulfur (TRS) compounds, expressed as an equivalent SO_2 concentration (dry basis) at zero percent oxygen.

[80 FR 75309, Dec. 1, 2015]

Table 30 to Subpart UUU of Part 63—Operating Limits for HAP Emissions From Sulfur Recovery Units

As stated in §63.1568(a)(2), you shall meet each operating limit in the following table that applies to you.

For . . .	**If use this type of control device . . .**	**You shall meet this operating limit . . .**
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	Not applicable	Not applicable.

For . . .	If use this type of control device . . .	You shall meet this operating limit . . .
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	Not applicable	Not applicable.
3. Option 2: TRS limit, if using continuous emissions monitoring systems. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	Not applicable	Not applicable.
4. Option 2: TRS limit, if using continuous parameter monitoring systems. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	Thermal incinerator	Maintain the daily average combustion zone temperature above the limit established during the performance test; and maintain the daily average oxygen concentration in the vent stream (percent, dry basis) above the limit established during the performance test.
5. Startup or shutdown option 1: Electing to comply with §63.1568(a)(4)(ii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown	Flare	On and after January 30, 2019, meet the applicable requirements of §63.670. Prior to January 30, 2019, meet the applicable requirements of either §63.11(b) or §63.670.
6. Startup or shutdown option 2: Electing to comply with §63.1568(a)(4)(iii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during startup or shutdown events	Thermal incinerator or thermal oxidizer	Maintain the hourly average combustion zone temperature at or above 1,200 degrees Fahrenheit and maintain the hourly average oxygen concentration in the exhaust gas stream at or above 2 volume percent (dry basis).

[80 FR 75310, Dec. 1, 2015]

Table 31 to Subpart UUU of Part 63—Continuous Monitoring Systems for HAP Emissions From Sulfur Recovery Units

As stated in §63.1568(b)(1), you shall meet each requirement in the following table that applies to you.

For . . .	For this limit . . .	You shall install and operate this continuous monitoring system . . .
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air if you use an oxidation or reduction control system followed by incineration	Continuous emission monitoring system to measure and record the hourly average concentration of SO_2 (dry basis) at zero percent excess air for each exhaust stack. This system must include an oxygen monitor for correcting the data for excess air.

For . . .	**For this limit . . .**	**You shall install and operate this continuous monitoring system . . .**
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air if you use a reduction control system without incineration	Continuous emission monitoring system to measure and record the hourly average concentration of reduced sulfur and oxygen (O_2) emissions. Calculate the reduced sulfur emissions as SO_2 (dry basis) at zero percent excess air. *Exception:* You can use an instrument having an air or SO_2 dilution and oxidation system to convert the reduced sulfur to SO_2 for continuously monitoring and recording the concentration (dry basis) at zero percent excess air of the resultant SO_2 instead of the reduced sulfur monitor. The monitor must include an oxygen monitor for correcting the data for excess oxygen.
	c. If you use Equation 1 of 40 CFR 60.102a(f)(1)(i) to set your emission limit	i. Complete either item 1.a or item 1.b; and ii. Either a continuous emission monitoring system to measure and record the O_2 concentration for the inlet air/oxygen supplied to the system or a continuous parameter monitoring system to measure and record the volumetric gas flow rate of ambient air and purchased oxygen-enriched gas.
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air if you use an oxidation or reduction control system followed by incineration	Continuous emission monitoring system to measure and record the hourly average concentration of SO_2 (dry basis), at zero percent excess air for each exhaust stack. This system must include an oxygen monitor for correcting the data for excess air.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air if you use a reduction control system without incineration.	Continuous emission monitoring system to measure and record the hourly average concentration of reduced sulfur and O_2 emissions for each exhaust stack. Calculate the reduced sulfur emissions as SO_2 (dry basis), at zero percent excess air. *Exception:* You can use an instrument having an air or O_2 dilution and oxidation system to convert the reduced sulfur to SO_2 for continuously monitoring and recording the concentration (dry basis) at zero percent excess air of the resultant SO_2 instead of the reduced sulfur monitor. The monitor must include an oxygen monitor for correcting the data for excess oxygen.
	c. If you use Equation 1 of 40 CFR 60.102a(f)(1)(i) to set your emission limit	i. Complete either item 2.a or item 2.b; and ii. Either a continuous emission monitoring system to measure and record the O_2 concentration for the inlet air/oxygen supplied to the system, or a continuous parameter monitoring system to measure and record the volumetric gas flow rate of ambient air and purchased oxygen-enriched gas.

For . . .	For this limit . . .	You shall install and operate this continuous monitoring system . . .
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1).	a. 300 ppmv of total reduced sulfur (TRS) compounds, expressed as an equivalent SO_2 concentration (dry basis) at zero percent oxygen	i. Continuous emission monitoring system to measure and record the hourly average concentration of TRS for each exhaust stack; this monitor must include an oxygen monitor for correcting the data for excess oxygen; or
		ii. Continuous parameter monitoring systems to measure and record the combustion zone temperature of each thermal incinerator and the oxygen content (percent, dry basis) in the vent stream of the incinerator.
4. Startup or shutdown option 1: electing to comply with §63.1568(a)(4)(ii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown.	Any	On and after January 30, 2019, monitoring systems as specified in §§63.670 and 63.671. Prior to January 30, 2019, either continuous parameter monitoring systems following the requirements in §63.11 (to detect the presence of a flame; to measure and record the net heating value of the gas being combusted; and to measure and record the volumetric flow of the gas being combusted) or monitoring systems as specified in §§63.670 and 63.671.
5. Startup or shutdown option 2: electing to comply with §63.1568(a)(4)(iii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown.	Any	Continuous parameter monitoring systems to measure and record the firebox temperature of each thermal incinerator or oxidizer and the oxygen content (percent, dry basis) in the exhaust vent from the incinerator or oxidizer.

[80 FR 75310, Dec. 1, 2015]

Table 32 to Subpart UUU of Part 63—Requirements for Performance Tests for HAP Emissions From Sulfur Recovery Units Not Subject to the New Source Performance Standards for Sulfur Oxides

As stated in §63.1568(b)(2) and (3), you shall meet each requirement in the following table that applies to you.

For . . .	You must . . .	Using . . .	According to these requirements . . .
1. Option 1: Elect NSPS. Each new and existing sulfur recovery unit	a. Measure SO_2 concentration (for an oxidation or reduction system followed by incineration) or measure the concentration of reduced sulfur (or SO_2 if you use an instrument to convert the reduced sulfur to SO_2) for a reduction control system without incineration	Data from continuous emission monitoring system	Collect SO_2 monitoring data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period.

For . . .	**You must . . .**	**Using . . .**	**According to these requirements . . .**
	b. Measure O_2 concentration for the inlet air/oxygen supplied to the system, if using Equation 1 of 40 CFR 60.102a(f)1)(i) to set your emission limit. You may use either an O_2 CEMS method in item 1.b.i of this table or the flow monitor in item 1.b.ii of this table	i. Data from continuous emission monitoring system; or	Collect O_2 monitoring data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period; and average over the 24-hour period for input to Equation 1 of 40 CFR 60.102a(f)(1)(i).
		ii. Data from flow monitor for ambient air and purchased oxygen-enriched gas	Collect gas flow rate monitoring data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from 4 or more data points equally spaced over each 1-hour period; calculate the hourly O_2 percent using Equation 10 of 40 CFR 60.106a(a)(6)(iv); and average over the 24-hour period for input to Equation 1 of 40 CFR 60.102a(f)(1)(i).
2. Option 2: TRS limit, using CEMS. Each new and existing sulfur recovery unit	Measure the concentration of reduced sulfur (or SO_2 if you use an instrument to convert the reduced sulfur to SO_2)	Data from continuous emission monitoring system	Collect TRS data every 15 minutes for 24 consecutive operating hours. Reduce the data to 1-hour averages computed from four or more data points equally spaced over each 1-hour period.
3. Option 2: TRS limit, if using continuous parameter monitoring systems. Each new and existing sulfur recovery unit	a. Select sampling port's location and the number of traverse ports	Method 1 or 1A in Appendix A-1 to part 60 of this chapter	Sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere.
	b. Determine velocity and volumetric flow rate	Method 2, 2A, 2C, 2D, or 2F in appendix A-1 to part 60 of this chapter, or Method 2G in appendix A-2 to part 60 of this chapter, as applicable	
	c. Conduct gas molecular weight analysis; obtain the oxygen concentration needed to correct the emission rate for excess air	Method 3, 3A, or 3B in appendix A-2 to part 60 of this chapter, as applicable	Take the samples simultaneously with reduced sulfur or moisture samples.
	d. Measure moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter	Make your sampling time for each Method 4 sample equal to that for 4 Method 15 samples.

For . . .	You must . . .	Using . . .	According to these requirements . . .
	e. Measure the concentration of TRS	Method 15 or 15A in appendix A-5 to part 60 of this chapter, as applicable	If the cross-sectional area of the duct is less than 5 square meters (m^2) or 54 square feet, you must use the centroid of the cross section as the sampling point. If the cross-sectional area is 5 m^2 or more and the centroid is more than 1 meter (m) from the wall, your sampling point may be at a point no closer to the walls than 1 m or 39 inches. Your sampling rate must be at least 3 liters per minute or 0.10 cubic feet per minute to ensure minimum residence time for the sample inside the sample lines.
	f. Calculate the SO_2 equivalent for each run after correcting for moisture and oxygen	The arithmetic average of the SO_2 equivalent for each sample during the run	
	g. Correct the reduced sulfur samples to zero percent excess air	Equation 1 of §63.1568	
	h. Establish each operating limit in Table 30 of this subpart that applies to you	Data from the continuous parameter monitoring system	
	i. Measure thermal incinerator: combustion zone temperature	Data from the continuous parameter monitoring system	Collect temperature monitoring data every 15 minutes during the entire period of the performance test; and determine and record the minimum hourly average temperature from all the readings.
	j. Measure thermal incinerator: oxygen concentration (percent, dry basis) in the vent stream	Data from the continuous parameter monitoring system	Collect oxygen concentration (percent, dry basis) data every 15 minutes during the entire period of the performance test; and determine and record the minimum hourly average percent excess oxygen concentration.

[80 FR 75312, Dec. 1, 2015]

Table 33 to Subpart UUU of Part 63—Initial Compliance With HAP Emission Limits for Sulfur Recovery Units

As stated in §63.1568(b)(5), you shall meet each requirement in the following table that applies to you.

For . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
1. Subject to NSPS: Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	a. 250 ppmv (dry basis) SO_2 at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation or reduction control system followed by incineration	You have already conducted a performance test to demonstrate initial compliance with the NSPS and each 12-hour rolling average concentration of SO_2 emissions measured by the continuous emission monitoring system is less than or equal to 250 ppmv (dry basis) at zero percent excess air, or the concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i). As part of the Notification of Compliance Status, you must certify that your vent meets the SO_2 limit. You are not required to do another performance test to demonstrate initial compliance.
		You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in §63.1572. You are not required to do another performance evaluation to demonstrate initial compliance.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration	You have already conducted a performance test to demonstrate initial compliance with the NSPS and each 12-hour rolling average concentration of reduced sulfur compounds measured by your continuous emission monitoring system is less than or equal to 300 ppmv, calculated as ppmv SO_2 (dry basis) at zero percent excess air, or the concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i). As part of the Notification of Compliance Status, you must certify that your vent meets the SO_2 limit. You are not required to do another performance test to demonstrate initial compliance.
		You have already conducted a performance evaluation to demonstrate initial compliance with the applicable performance specification. As part of your Notification of Compliance Status, you must certify that your continuous emission monitoring system meets the applicable requirements in §63.1572. You are not required to do another performance evaluation to demonstrate initial compliance.

For . . .	For the following emission limit . . .	You have demonstrated initial compliance if . . .
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation or reduction control system followed by incineration	Each 12-hour rolling average concentration of SO_2 emissions measured by the continuous emission monitoring system during the initial performance test is less than or equal to 250 ppmv (dry basis) at zero percent excess air, or the concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i); and your performance evaluation shows the monitoring system meets the applicable requirements in §63.1572.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration	Each 12-hour rolling average concentration of reduced sulfur compounds measured by the continuous emission monitoring system during the initial performance test is less than or equal to 300 ppmv, calculated as ppmv SO_2 (dry basis) at zero percent excess air, or the concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i); and your performance evaluation shows the continuous emission monitoring system meets the applicable requirements in §63.1572.
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	300 ppmv of TRS compounds expressed as an equivalent SO_2 concentration (dry basis) at zero percent oxygen	If you use continuous parameter monitoring systems, the average concentration of TRS emissions measured using Method 15 during the initial performance test is less than or equal to 300 ppmv expressed as equivalent SO_2 concentration (dry basis) at zero percent oxygen. If you use a continuous emission monitoring system, each 12-hour rolling average concentration of TRS emissions measured by the continuous emission monitoring system during the initial performance test is less than or equal to 300 ppmv expressed as an equivalent SO_2 (dry basis) at zero percent oxygen; and your performance evaluation shows the continuous emission monitoring system meets the applicable requirements in §63.1572.

[80 FR 75313, Dec. 1, 2015]

Table 34 to Subpart UUU of Part 63—Continuous Compliance With HAP Emission Limits for Sulfur Recovery Units

As stated in §63.1568(c)(1), you shall meet each requirement in the following table that applies to you.

For . . .	For this emission limit . . .	You shall demonstrate continuous compliance by . . .
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation or reduction control system followed by incineration	Collecting the hourly average SO_2 monitoring data (dry basis, percent excess air) and, if using Equation 1 of 40 CFR 60.102a(f)(1)(i), collecting the hourly O_2 concentration or flow monitoring data according to §63.1572; determining and recording each 12-hour rolling average concentration of SO_2; maintaining each 12-hour rolling average concentration of SO_2 at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of SO_2 greater than the applicable emission limitation in the semiannual compliance report required by §63.1575.
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration	Collecting the hourly average reduced sulfur (and air or O_2 dilution and oxidation) monitoring data and, if using Equation 1 of 40 CFR 60.102a(f)(1)(i), collecting the hourly O_2 concentration or flow monitoring data according to §63.1572; determining and recording each 12-hour rolling average concentration of reduced sulfur; maintaining each 12-hour rolling average concentration of reduced sulfur at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of reduced sulfur greater than the applicable emission limitation in the semiannual compliance report required by §63.1575.
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	a. 250 ppmv (dry basis) of SO_2 at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use an oxidation or reduction control system followed by incineration	Collecting the hourly average SO_2 data (dry basis, percent excess air) and, if using Equation 1 of 40 CFR 60.102a(f)(1)(i), collecting the hourly O_2 concentration or flow monitoring data according to §63.1572; determining and recording each 12-hour rolling average concentration of SO_2; maintaining each 12-hour rolling average concentration of SO_2 at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of SO_2 greater than the applicable emission limitation in the semiannual compliance report required by §63.1575.

For . . .	For this emission limit . . .	You shall demonstrate continuous compliance by . . .
	b. 300 ppmv of reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air, or concentration determined using Equation 1 of 40 CFR 60.102a(f)(1)(i), if you use a reduction control system without incineration	Collecting the hourly average reduced sulfur (and air or O_2 dilution and oxidation) monitoring data and, if using Equation 1 of 40 CFR 60.102a(f)(1)(i), collecting the hourly O_2 concentration or flow monitoring data according to §63.1572; determining and recording each 12-hour rolling average concentration of reduced sulfur; maintaining each 12-hour rolling average concentration of reduced sulfur at or below the applicable emission limitation; and reporting any 12-hour rolling average concentration of reduced sulfur greater than the applicable emission limitation in the semiannual compliance report required by §63.1575.
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	300 ppmv of TRS compounds, expressed as an SO_2 concentration (dry basis) at zero percent oxygen or reduced sulfur compounds calculated as ppmv SO_2 (dry basis) at zero percent excess air	i. If you use continuous parameter monitoring systems, collecting the hourly average TRS monitoring data according to §63.1572 and maintaining each 12-hour average concentration of TRS at or below the applicable emission limitation; or
		ii. If you use a continuous emission monitoring system, collecting the hourly average TRS monitoring data according to §63.1572, determining and recording each 12-hour rolling average concentration of TRS; maintaining each 12-hour rolling average concentration of TRS at or below the applicable emission limitation; and reporting any 12-hour rolling average TRS concentration greater than the applicable emission limitation in the semiannual compliance report required by §63.1575.

[80 FR 75315, Dec. 1, 2015]

Table 35 to Subpart UUU of Part 63—Continuous Compliance With Operating Limits for HAP Emissions From Sulfur Recovery Units

As stated in §63.1568(c)(1), you shall meet each requirement in the following table that applies to you.

For . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
1. Subject to NSPS. Each new or existing Claus sulfur recovery unit part of a sulfur recovery plant with design capacity greater than 20 LTD and subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	Not applicable	Meeting the requirements of Table 34 of this subpart.
2. Option 1: Elect NSPS. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	Not applicable	Meeting the requirements of Table 34 of this subpart.

For . . .	For this operating limit . . .	You shall demonstrate continuous compliance by . . .
3. Option 2: TRS limit. Each new or existing sulfur recovery unit (Claus or other type, regardless of size) not subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) or 60.102a(f)(1)	a. Maintain the daily average combustion zone temperature above the level established during the performance test	Collecting the hourly and daily average temperature monitoring data according to §63.1572; and maintaining the daily average combustion zone temperature at or above the limit established during the performance test
	b. The daily average oxygen concentration in the vent stream (percent, dry basis) must not fall below the level established during the performance test.	Collecting the hourly and daily average O_2 monitoring data according to §63.1572; and maintaining the average O_2 concentration above the level established during the performance test.
4. Startup or shutdown option 1: Electing to comply with §63.1568(a)(4)(ii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown	Using a flare meeting the requirements in §63.11(b) or §63.670	On and after January 30, 2019, complying with the applicable requirements of §63.670. Prior to January 30, 2019, complying with the applicable requirements of either §63.11(b) or §63.670.
5. Startup or shutdown option 2: Electing to comply with §63.1568(a)(4)(iii). Each new or existing sulfur recovery unit (Claus or other type, regardless of size) during periods of startup or shutdown	a. Minimum hourly average temperature of 1,200 degrees Fahrenheit	Collecting continuous (at least once every 15 minutes) and hourly average temperature monitoring data according to §63.1572; and maintaining the daily average firebox temperature at or above 1,200 degrees Fahrenheit.
	b. Minimum hourly average outlet oxygen concentration of 2 volume percent (dry basis)	Collecting continuous (at least once every 15 minutes) and hourly average O_2 monitoring data according to §63.1572; and maintaining the average O_2 concentration at or above 2 volume percent (dry basis).

[80 FR 75316, Dec. 1, 2015]

Table 36 to Subpart UUU of Part 63—Work Practice Standards for HAP Emissions From Bypass Lines

As stated in §63.1569(a)(1), you shall meet each work practice standard in the following table that applies to you.

Option	You shall meet one of these equipment standards . . .
1. Option 1	Install and operate a device (including a flow indicator, level recorder, or electronic valve position monitor) to demonstrate, either continuously or at least every hour, whether flow is present in the by bypass line. Install the device at or as near as practical to the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.
2. Option 2	Install a car-seal or lock-and-key device placed on the mechanism by which the bypass device flow position is controlled (e.g., valve handle, damper level) when the bypass device is in the closed position such that the bypass line valve cannot be opened without breaking the seal or removing the device.
3. Option 3	Seal the bypass line by installing a solid blind between piping flanges.
4. Option 4	Vent the bypass line to a control device that meets the appropriate requirements in this subpart.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6964, Feb. 9, 2005]

Table 37 to Subpart UUU of Part 63—Requirements for Performance Tests for Bypass Lines

As stated in §63.1569(b)(1), you shall meet each requirement in the following table that applies to you.

For this standard . . .	You shall . . .
1. Option 1: Install and operate a flow indicator, level recorder, or electronic valve position monitor.	Record during the performance test for each type of control device whether the flow indicator, level recorder, or electronic valve position monitor was operating and whether flow was detected at any time during each hour of level the three runs comprising the performance test.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

Table 38 to Subpart UUU of Part 63—Initial Compliance With Work Practice Standards for HAP Emissions From Bypass Lines

As stated in §63.1569(b)(2), you shall meet each requirement in the following table that applies to you.

Option . . .	For this work practice standard . . .	You have demonstrated initial compliance if . . .
1. Each new or existing bypass line associated with a catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit	a. Option 1: Install and operate a device (including a flow indicator, level recorder, or electronic valve position monitor) to demonstrate, either continuously or at least every hour, whether flow is present in bypass line. Install the device at or as near as practical to the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere	The installed equipment operates properly during each run of the performance test and no flow is present in the line during the test.
	b. Option 2: Install a car-seal or lock-and-key device placed on the mechanism by which the bypass device flow position is controlled (e.g., valve handle, damper level) when the bypass device is in the closed position such that the bypass line valve cannot be opened without breaking the seal or removing the device	As part of the notification of compliance status, you certify that you installed the equipment, the equipment was operational by your compliance date, and you identify what equipment was installed.
	c. Option 3: Seal the bypass line by installing a solid blind between piping flanges	See item 1.b of this table.
	d. Option 4: Vent the bypass line to a control device that meets the appropriate requirements in this subpart	See item 1.b of this table.

[70 FR 6965, Feb. 9, 2005]

Table 39 to Subpart UUU of Part 63—Continuous Compliance With Work Practice Standards for HAP Emissions From Bypass Lines

As stated in §63.1569(c)(1), you shall meet each requirement in the following table that applies to you.

If you elect this standard . . .	You shall demonstrate continuous compliance by . . .
1. Option 1: Flow indicator, level recorder, or electronic valve position monitor.	Monitoring and recording on a continuous basis or at least every hour whether flow is present in the bypass line; visually inspecting the device at least once every hour if the device is not equipped with a recording system that provides a continuous record; and recording whether the device is operating properly and whether flow is present in the bypass line.
2. Option 2: Car-seal or lock-and-key device	Visually inspecting the seal or closure mechanism at least once every month; and recording whether the bypass line valve is maintained in the closed position and whether flow is present in the line.
3. Option 3: Solid blind flange	Visually inspecting the blind at least once a month; and recording whether the blind is maintained in the correct position such that the vent stream cannot be diverted through the bypass line.
4. Option 4: Vent to control device	Monitoring the control device according to appropriate subpart requirements.
5. Option 1, 2, 3, or 4	Recording and reporting the time and duration of any bypass.

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, 6965, Feb. 9, 2005]

Table 40 to Subpart UUU of Part 63—Requirements for Installation, Operation, and Maintenance of Continuous Opacity Monitoring Systems and Continuous Emission Monitoring Systems

As stated in §63.1572(a)(1) and (b)(1), you shall meet each requirement in the following table that applies to you.

This type of continuous opacity or emission monitoring system . . .	Must meet these requirements . . .
1. Continuous opacity monitoring system	Performance specification 1 (40 CFR part 60, appendix B).
2. PM CEMS; this monitor must include an O_2 monitor for correcting the data for excess air	The requirements in 40 CFR 60.105a(d).
3. CO continuous emission monitoring system	Performance specification 4 (40 CFR part 60, appendix B); span value of 1,000 ppm; and procedure 1 (40 CFR part 60, appendix F) except relative accuracy test audits are required annually instead of quarterly.
4. CO continuous emission monitoring system used to demonstrate emissions average under 50 ppm (dry basis)	Performance specification 4 (40 CFR part 60, appendix B); and span value of 100 ppm.
5. SO_2 continuous emission monitoring system for sulfur recovery unit with oxidation control system or reduction control system; this monitor must include an O_2 monitor for correcting the data for excess air	Performance specification 2 (40 CFR part 60, appendix B); span value of 500 ppm SO_2, or if using Equation 1 of 40 CFR 60.102a(f)(1)(i), span value of two times the limit at the highest O_2 concentration; use Methods 6 or 6C (40 CFR part 60, appendix A-4) for certifying the SO_2 monitor and Methods 3A or 3B (40 CFR part 60, appendix A-2) for certifying the O_2 monitor; and procedure 1 (40 CFR part 60, appendix F) except relative accuracy test audits are required annually instead of quarterly.

This type of continuous opacity or emission monitoring system . . .	Must meet these requirements . . .
6. Reduced sulfur and O_2 continuous emission monitoring system for sulfur recovery unit with reduction control system not followed by incineration; this monitor must include an O_2 monitor for correcting the data for excess air unless exempted	Performance specification 5 (40 CFR part 60, appendix B), except calibration drift specification is 2.5 percent of the span value instead of 5 percent; span value is 450 ppm reduced sulfur, or if using Equation 1 of 40 CFR 60.102a(f)(1)(i), span value of two times the limit at the highest O_2 concentration; use Methods 15 or 15A (40 CFR part 60, appendix A-5) for certifying the reduced sulfur monitor and Methods 3A or 3B (40 CFR part 60, appendix A-2) for certifying the O_2 monitor; if Method 3A or 3B yields O_2 concentrations below 0.25 percent during the performance evaluation, the O_2 concentration can be assumed to be zero and the O_2 monitor is not required; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.
7. Instrument with an air or O_2 dilution and oxidation system to convert reduced sulfur to SO_2 for continuously monitoring the concentration of SO_2 instead of reduced sulfur monitor and O_2 monitor	Performance specification 5 (40 CFR part 60, appendix B); span value of 375 ppm SO_2 or if using Equation 1 of 40 CFR 60.102a(f)(1)(i), span value of two times the limit at the highest O_2 concentration; use Methods 15 or 15A (40 CFR part 60, appendix A-5) for certifying the reduced sulfur monitor and 3A or 3B (40 CFR part 60, appendix A-2) for certifying the O_2 monitor; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.
8. TRS continuous emission monitoring system for sulfur recovery unit; this monitor must include an O_2 monitor for correcting the data for excess air	Performance specification 5 (40 CFR part 60, appendix B).
9. O_2 monitor for oxygen concentration	If necessary due to interferences, locate the oxygen sensor prior to the introduction of any outside gas stream; performance specification 3 (40 CFR part 60, appendix B; and procedure 1 (40 CFR part 60, appendix F), except relative accuracy test audits, are required annually instead of quarterly.

[80 FR 75317, Dec. 1, 2015]

Table 41 to Subpart UUU of Part 63—Requirements for Installation, Operation, and Maintenance of Continuous Parameter Monitoring Systems

As stated in §63.1572(c)(1), you shall meet each requirement in the following table that applies to you.

If you use . . .	You shall . . .
1. pH strips	Use pH strips with an accuracy of ±10 percent.
2. pH meter	Locate the pH sensor in a position that provides a representative measurement of pH; ensure the sample is properly mixed and representative of the fluid to be measured.
	Use a pH sensor with an accuracy of at least ±0.2 pH units.
	Check the pH meter's calibration on at least one point at least once daily; check the pH meter's calibration on at least two points at least once quarterly; at least monthly, inspect all components for integrity and all electrical components for continuity; record the results of each calibration check and inspection.
3. Colormetric tube sampling system	Use a colormetric tube sampling system with a printed numerical scale in ppmv, a standard measurement range of 1 to 10 ppmv (or 1 to 30 ppmv if applicable), and a standard deviation for measured values of no more than ±15 percent. System must include a gas detection pump and hot air probe if needed for the measurement range.

If you use . . .	**You shall . . .**
4. CO_2, O_2, and CO monitors for coke burn-off rate	a. Locate the concentration sensor so that it provides a representative measurement of the content of the exit gas stream; ensure the sample is properly mixed and representative of the gas to be measured.
	Use a sensor with an accuracy of at least ±1 percent of the range of the sensor or to a nominal gas concentration of ±0.5 percent, whichever is greater.
	Use a monitor that is able to measure concentration on a dry basis or is able to correct for moisture content and record on a dry basis.
	Conduct calibration checks at least annually; conduct calibration checks following any period of more than 24 hours throughout which the sensor reading exceeds the manufacturer's specified maximum operating range or install a new sensor; at least quarterly, inspect all components for integrity and all electrical connections for continuity; record the results of each calibration and inspection.
	b. As an alternative, the requirements in 40 CFR 60.105a(b)(2) may be used.
5. BLD	Follow the requirements in 40 CFR 60.105a(c).
6. Voltage, secondary current, or total power input sensors	Use meters with an accuracy of at least ±5 percent over the operating range.
	Each time that the unit is not operating, confirm that the meters read zero. Conduct a calibration check at least annually; conduct calibration checks following any period of more than 24 hours throughout which the meter reading exceeds the manufacturer's specified maximum operating range; at least monthly, inspect all components of the continuous parameter monitoring system for integrity and all electrical connections for continuity; record the results of each calibration check and inspection.
7. Pressure/Pressure drop[1] sensors	Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.
	Use a gauge with an accuracy of at least ±5 percent over the normal operating range or 0.12 kilopascals (0.5 inches of water column), whichever is greater.
	Review pressure sensor readings at least once a week for straightline (unchanging) pressure and perform corrective action to ensure proper pressure sensor operation if blockage is indicated; using an instrument recommended by the sensor's manufacturer, check gauge calibration and transducer calibration annually; conduct calibration checks following any period of more than 24 hours throughout which the pressure exceeded the manufacturer's specified maximum rated pressure or install a new pressure sensor; at least quarterly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage, unless the CPMS has a redundant pressure sensor; record the results of each calibration check and inspection.
8. Air flow rate, gas flow rate, or total water (or scrubbing liquid) flow rate sensors	Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances. If you elect to comply with Option 3 (Ni lb/hr) or Option 4 (Ni lb/1,000 lb of coke burn-off) for the HAP metal emission limitations in §63.1564, install the continuous parameter monitoring system for gas flow rate as close as practical to the continuous opacity monitoring system; and if you don't use a continuous opacity monitoring system, install the continuous parameter monitoring system for gas flow rate as close as practical to the control device.
	Use a flow rate sensor with an accuracy of at least ±5 percent over the normal range of flow measured, or 1.9 liter per minute (0.5 gallons per minute), whichever is greater, for liquid flow.

If you use . . .	You shall . . .
	Use a flow rate sensor with an accuracy of at least ±5 percent over the normal range of flow measured, or 280 liters per minute (10 cubic feet per minute), whichever is greater, for gas flow.
	Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer's specified maximum rated flow rate or install a new flow sensor; at least quarterly, inspect all components for leakage, unless the CPMS has a redundant flow sensor; record the results of each calibration check and inspection.
9. Temperature sensors	Locate the temperature sensor in the combustion zone, or in the ductwork immediately downstream of the combustion zone before any substantial heat exchange occurs or in the ductwork immediately downstream of the regenerator; locate the temperature sensor in a position that provides a representative temperature; shield the temperature sensor system from electromagnetic interference and chemical contaminants.
	Use a temperature sensor with an accuracy of at least ±1 percent over the normal range of temperature measured, expressed in degrees Celsius (C), or 2.8 degrees C, whichever is greater.
	Conduct calibration checks at least annually; conduct calibration checks following any period of more than 24 hours throughout which the temperature exceeded the manufacturer's specified maximum rated temperature or install a new temperature sensor; at least quarterly, inspect all components for integrity and all electrical connections for continuity, oxidation, and galvanic corrosion, unless the CPMS has a redundant temperature sensor; record the results of each calibration check and inspection.
10. Oxygen content sensors[2]	Locate the oxygen sensor so that it provides a representative measurement of the oxygen content of the exit gas stream; ensure the sample is properly mixed and representative of the gas to be measured.
	Use an oxygen sensor with an accuracy of at least ±1 percent of the range of the sensor or to a nominal gas concentration of ±0.5 percent, whichever is greater.
	Conduct calibration checks at least annually; conduct calibration checks following any period of more than 24 hours throughout which the sensor reading exceeds the manufacturer's specified maximum operating range or install a new oxygen sensor; at least quarterly, inspect all components for integrity and all electrical connections for continuity; record the results of each calibration and inspection.

[1] Not applicable to non-venturi wet scrubbers of the jet-ejector design.

[2] This does not replace the requirements for oxygen monitors that are required to use continuous emissions monitoring systems. The requirements in this table apply to oxygen sensors that are continuous parameter monitors, such as those that monitor combustion zone oxygen concentration and regenerator exit oxygen concentration.

[80 FR 75318, Dec. 1, 2015]

Table 42 to Subpart UUU of Part 63—Additional Information for Initial Notification of Compliance Status

As stated in §63.1574(d), you shall meet each requirement in the following table that applies to you.

For . . .	You shall provide this additional information . . .
1. Identification of affected sources and emission points.	Nature, size, design, method of operation, operating design capacity of each affected source; identify each emission point for each HAP; identify any affected source or vent associated with an affected source not subject to the requirements of subpart UUU.

For . . .	You shall provide this additional information . . .
2. Initial compliance	Identification of each emission limitation you will meet for each affected source, including any option you select (i.e., NSPS, PM or Ni, flare, percent reduction, concentration, options for bypass lines); if applicable, certification that you have already conducted a performance test to demonstrate initial compliance with the NSPS for an affected source; certification that the vents meet the applicable emission limit and the continuous opacity or that the emission monitoring system meets the applicable performance specification; if applicable, certification that you have installed and verified the operational status of equipment by your compliance date for each bypass line that meets the requirements of Option 2, 3, or 4 in §63.1569 and what equipment you installed; identification of the operating limit for each affected source, including supporting documentation; if your affected source is subject to the NSPS, certification of compliance with NSPS emission limitations and performance specifications; a brief description of performance test conditions (capacity, feed quality, catalyst, etc.); an engineering assessment (if applicable); and if applicable, the flare design (e.g., steam-assisted, air-assisted, or non-assisted), all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the Method 22 test.
3. Continuous compliance	Each monitoring option you elect; and identification of any unit or vent for which monitoring is not required; and the definition of "operating day." (This definition, subject to approval by the applicable permitting authority, must specify the times at which a 24-hr operating day begins and ends.)

[67 FR 17773, Apr. 11, 2002, as amended at 70 FR 6942, Feb. 9, 2005]

Table 43 to Subpart UUU of Part 63—Requirements for Reports

As stated in §63.1575(a), you shall meet each requirement in the following table that applies to you.

You must submit . . .	The report must contain . . .	You shall submit the report . . .
1. A compliance report	If there are no deviations from any emission limitation or work practice standard that applies to you, a statement that there were no deviations from the standards during the reporting period and that no continuous opacity monitoring system or continuous emission monitoring system was inoperative, inactive, out-of-control, repaired, or adjusted; if you have a deviation from any emission limitation or work practice standard during the reporting period, the report must contain the information in §63.1575(c) through (e)	Semiannually according to the requirements in §63.1575(b).
2. Performance test and CEMS performance evaluation data	On and after January 30, 2019, the information specified in §63.1575(k)(1)	Within 60 days after the date of completing each test according to the requirements in §63.1575(k).

[80 FR 75319, Dec. 1, 2015]

Table 44 to Subpart UUU of Part 63—Applicability of NESHAP General Provisions to Subpart UUU

As stated in §63.1577, you shall meet each requirement in the following table that applies to you.

Citation	Subject	Applies to subpart UUU	Explanation
§63.1(a)(1)-(4)	General Applicability	Yes	

Citation	Subject	Applies to subpart UUU	Explanation
§63.1(a)(5)	[Reserved]	Not applicable	
§63.1(a)(6)		Yes	Except the correct mail drop (MD) number is C404-04.
§63.1(a)(7)-(9)	[Reserved]	Not applicable	
§63.1(a)(10)-(12)		Yes	Except that this subpart specifies calendar or operating day.
§63.1(b)(1)	Initial Applicability Determination for this part	Yes	
§63.1(b)(2)	[Reserved]	Not applicable	
§63.1(b)(3)		Yes	
§63.1(c)(1)	Applicability of this part after a Relevant Standard has been set under this part	Yes	
§63.1(c)(2)		No	Area sources are not subject to this subpart.
§63.1(c)(3)-(4)	[Reserved]	Not applicable	
§63.1(c)(5)		Yes	
§63.1(d)	[Reserved]	Not applicable	
§63.1(e)	Applicability of Permit Program	Yes	
§63.2	Definitions	Yes	§63.1579 specifies that if the same term is defined in subparts A and UUU of this part, it shall have the meaning given in this subpart.
§63.3	Units and Abbreviations	Yes	
§63.4(a)(1)-(2)	Prohibited Activities	Yes	
§63.4(a)(3)-(5)	[Reserved]	Not applicable	
§63.4(b)-(c)	Circumvention and Fragmentation	Yes	
§63.5(a)	Construction and Reconstruction	Yes	
§63.5(b)(1)		Yes	
§63.5(b)(2)	[Reserved]	Not applicable	
§63.5(b)(3)-(4)		Yes	In §63.5(b)(4), replace the reference to §63.9(b) with §63.9(b)(4) and (5).
§63.5(b)(5)	[Reserved]	Not applicable	
§63.5(b)(6)		Yes	

Citation	Subject	Applies to subpart UUU	Explanation
§63.5(c)	[Reserved]	Not applicable	
§63.5(d)(1)(i)	Application for Approval of Construction or Reconstruction—General Application Requirements	Yes	Except this subpart specifies the application is submitted as soon as practicable before startup but not later than 90 days after the promulgation date if construction or reconstruction had commenced and initial startup had not occurred before promulgation.
§63.5(d)(1)(ii)		Yes	Except that emission estimates specified in §63.5(d)(1)(ii)(H) are not required, and §63.5(d)(1)(ii)(G) and (I) are Reserved and do not apply.
§63.5(d)(1)(iii)		No	This subpart specifies submission of notification of compliance status.
§63.5(d)(2)		Yes	
§63.5(d)(3)		Yes	
§63.5(d)(4)		Yes	
§63.5(e)	Approval of Construction or Reconstruction	Yes	
§63.5(f)(1)	Approval of Construction or Reconstruction Based on State Review	Yes	
§63.5(f)(2)		Yes	Except that the cross-reference to §63.9(b)(2) does not apply.
§63.6(a)	Compliance with Standards and Maintenance—Applicability	Yes	
§63.6(b)(1)-(4)	Compliance Dates for New and Reconstructed Sources	Yes	
§63.6(b)(5)		Yes	Except that this subpart specifies different compliance dates for sources.
§63.6(b)(6)	[Reserved]	Not applicable	
§63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Yes	
§63.6(c)(1)-(2)	Compliance Dates for Existing Sources	Yes	Except that this subpart specifies different compliance dates for sources subject to Tier II gasoline sulfur control requirements.
§63.6(c)(3)-(4)	[Reserved]	Not applicable	
§63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major	Yes	
§63.6(d)	[Reserved]	Not applicable	

Citation	**Subject**	**Applies to subpart UUU**	**Explanation**
§63.6(e)(1)(i)	General Duty to Minimize Emissions	No	See §63.1570(c) for general duty requirement.
§63.6(e)(1)(ii)	Requirement to Correct Malfunctions as Soon as Possible	No	
§63.6(e)(1)(iii)	Compliance with Standards and Maintenance Requirements	Yes	
§63.6(e)(2)	[Reserved]	Not Applicable	
§63.6(e)(3)(i)	Startup, Shutdown, and Malfunction Plan Requirements	No	
§63.6(e)(3)(ii)	[Reserved]	Not applicable	
§63.6(e)(3)(iii)-(ix)		No	
§63.6(f)(1)	SSM Exemption	No	
§63.6(f)(2)(i)-(iii)(C)	Compliance with Standards and Maintenance Requirements	Yes	
§63.6(f)(2)(iii)(D)		Yes	
§63.6(f)(2)(iv)-(v)		Yes	
§63.6(f)(3)		Yes	Except the cross-references to §63.6(f)(1) and (e)(1)(i) are changed to §63.1570(c).
§63.6(g)	Alternative Standard	Yes	
§63.6(h)(1)	SSM Exemption for Opacity/VE Standards	No	
§63.6(h)(2)(i)	Determining Compliance with Opacity/VE Standards	No	This subpart specifies methods.
§63.6(h)(2)(ii)	[Reserved]	Not applicable	
§63.6(h)(2)(iii)		Yes	
§63.6(h)(3)	[Reserved]	Not applicable	
§63.6(h)(4)	Notification of Opacity/VE Observation Date	Yes	Applies to Method 22 (40 CFR part 60, appendix A-7) tests.
§63.6(h)(5)	Conducting Opacity/VE Observations	No	
§63.6(h)(6)	Records of Conditions During Opacity/VE Observations	Yes	Applies to Method 22 (40 CFR part 60, appendix A-7) observations.
§63.6(h)(7)(i)	Report COM Monitoring Data from Performance Test	Yes	
§63.6(h)(7)(ii)	Using COM Instead of Method 9	No	

Citation	Subject	Applies to subpart UUU	Explanation
§63.6(h)(7)(iii)	Averaging Time for COM during Performance Test	Yes	
§63.6(h)(7)(iv)	COM Requirements	Yes	
§63.6(h)(7)(v)	COMS Results and Visual Observations	Yes	
§63.6(h)(8)	Determining Compliance with Opacity/VE Standards	Yes	
§63.6(h)(9)	Adjusted Opacity Standard	Yes	
§63.6(i)(1)-(14)	Extension of Compliance	Yes	Extension of compliance under §63.6(i)(4) not applicable to a facility that installs catalytic cracking feed hydrotreating and receives an extended compliance date under §63.1563(c).
§63.6(i)(15)	[Reserved]	Not applicable	
§63.6(i)(16)		Yes	
§63.6(j)	Presidential Compliance Exemption	Yes	
§63.7(a)(1)	Performance Test Requirements Applicability	Yes	Except that this subpart specifies the applicable test and demonstration procedures.
§63.7(a)(2)	Performance Test Dates	Yes	Except test results must be submitted in the Notification of Compliance Status report due 150 days after the compliance date.
§63.7(a)(3)	Section 114 Authority	Yes	
§63.7(a)(4)	Force Majeure	Yes	
§63.7(b)	Notifications	Yes	Except that this subpart specifies notification at least 30 days prior to the scheduled test date rather than 60 days.
§63.7(c)	Quality Assurance Program/Site-Specific Test Plan	Yes	Except that when this subpart specifies to use 40 CFR part 60, appendix F, out of control periods are to be defined as specified in part 60, appendix F.
§63.7(d)	Performance Test Facilities	Yes	
§63.7(e)(1)	Performance Testing	No	See §63.1571(b)(1).
§63.7(e)(2)-(4)	Conduct of Tests	Yes	
§63.7(f)	Alternative Test Method	Yes	
§63.7(g)	Data Analysis, Recordkeeping, Reporting	Yes	Except performance test reports must be submitted with notification of compliance status due 150 days after the compliance date, and §63.7(g)(2) is reserved and does not apply.
§63.7(h)	Waiver of Tests	Yes	
§63.8(a)(1)	Monitoring Requirements-Applicability	Yes	
§63.8(a)(2)	Performance Specifications	Yes	

Citation	Subject	Applies to subpart UUU	Explanation
§63.8(a)(3)	[Reserved]	Not applicable	
§63.8(a)(4)	Monitoring with Flares	Yes	Except that for a flare complying with §63.670, the cross-reference to §63.11 in this paragraph does not include §63.11(b).
§63.8(b)(1)	Conduct of Monitoring	Yes	
§63.8(b)(2)-(3)	Multiple Effluents and Multiple Monitoring Systems	Yes	This subpart specifies the required monitoring locations.
§63.8(c)(1)	Monitoring System Operation and Maintenance	Yes	
§63.8(c)(1)(i)	General Duty to Minimize Emissions and CMS Operation	No	See §63.1570(c).
§63.8(c)(1)(ii)	Keep Necessary Parts for CMS	Yes	
§63.8(c)(1)(iii)	Requirement to Develop SSM Plan for CMS	No	
§63.8(c)(2)-(3)	Monitoring System Installation	Yes	Except that this subpart specifies that for continuous parameter monitoring systems, operational status verification includes completion of manufacturer written specifications or installation, operation, and calibration of the system or other written procedures that provide adequate assurance that the equipment will monitor accurately.
§63.8(c)(4)	Continuous Monitoring System Requirements	Yes	
§63.8(c)(5)	COMS Minimum Procedures	Yes	
§63.8(c)(6)	CMS Requirements	Yes	
§63.8(c)(7)-(8)	CMS Requirements	Yes	
§63.8(d)(1)-(2)	Quality Control Program for CMS	Yes	
§63.8(d)(3)	Written Procedures for CMS	No	
§63.8(e)	CMS Performance Evaluation	Yes	Except that results are to be submitted as part of the Notification Compliance Status due 150 days after the compliance date.
§63.8(f)(1)-(5)	Alternative Monitoring Methods	Yes	Except that this subpart specifies procedures for requesting alternative monitoring systems and alternative parameters.
§63.8(f)(6)	Alternative to Relative Accuracy Test	Yes	Applicable to continuous emission monitoring systems if performance specification requires a relative accuracy test audit.
§63.8(g)(1)-(4)	Reduction of Monitoring Data	Yes	Applies to continuous opacity monitoring system or continuous emission monitoring system.
§63.8(g)(5)	Data Reduction	No	This subpart specifies requirements.
§63.9(a)	Notification Requirements—Applicability	Yes	Duplicate Notification of Compliance Status report to the Regional Administrator may be required.

Citation	**Subject**	**Applies to subpart UUU**	**Explanation**
§63.9(b)(1)-(2)	Initial Notifications	Yes	Except that notification of construction or reconstruction is to be submitted as soon as practicable before startup but no later than 30 days after the effective date if construction or reconstruction had commenced but startup had not occurred before the effective date.
§63.9(b)(3)	[Reserved]	Not applicable	
§63.9(b)(4)-(5)	Initial Notification Information	Yes	Except §63.9(b)(4)(ii)-(iv), which are reserved and do not apply.
§63.9(c)	Request for Extension of Compliance	Yes	
§63.9(d)	New Source Notification for Special Compliance Requirements	Yes	
§63.9(e)	Notification of Performance Test	Yes	Except that notification is required at least 30 days before test.
§63.9(f)	Notification of VE/Opacity Test	Yes	
§63.9(g)	Additional Notification Requirements for Sources with Continuous Monitoring Systems	Yes	
§63.9(h)	Notification of Compliance Status	Yes	Except that this subpart specifies the notification is due no later than 150 days after compliance date, and except that the reference to §63.5(d)(1)(ii)(H) in §63.9(h)(5) does not apply.
§63.9(i)	Adjustment of Deadlines	Yes	
§63.9(j)	Change in Previous Information	Yes	
63.10(a)	Recordkeeping and Reporting Applicability	Yes	
§63.10(b)(1)	General Recordkeeping Requirements	Yes	
§63.10(b)(2)(i)	Recordkeeping of Occurrence and Duration of Startups and Shutdowns	No	
§63.10(b)(2)(ii)	Recordkeeping of Malfunctions	No	See §63.1576(a)(2) for recordkeeping of (1) date, time and duration; (2) listing of affected source or equipment, and an estimate of the volume of each regulated pollutant emitted over the standard; and (3) actions taken to minimize emissions and correct the failure.
§63.10(b)(2)(iii)	Maintenance Records	Yes	
§63.10(b)(2)(iv)-(v)	Actions Taken to Minimize Emissions During SSM	No	
§63.10(b)(2)(vi)	Recordkeeping for CMS Malfunctions	Yes	

Citation	**Subject**	**Applies to subpart UUU**	**Explanation**
§63.10(b)(2)(vii)-(xiv)	Other CMS Requirements	Yes	
§63.10(b)(3)	Recordkeeping for Applicability Determinations.	Yes	
§63.10(c)(1)-(6)	Additional Records for Continuous Monitoring Systems	Yes	Except §63.10(c)(2)-(4), which are Reserved and do not apply.
§63.10(c)(7)-(8)	Additional Recordkeeping Requirements for CMS—Identifying Exceedances and Excess Emissions	Yes	
§63.10(c)(9)	[Reserved]	Not applicable	
§63.10(c)(10)	Recording Nature and Cause of Malfunctions	No	See §63.1576(a)(2) for malfunctions recordkeeping requirements.
§63.10(c)(11)	Recording Corrective Actions	No	See §63.1576(a)(2) for malfunctions recordkeeping requirements.
§63.10(c)(12)-(14)	Additional CMS Recordkeeping Requirements	Yes	
§63.10(c)(15)	Use of SSM Plan	No	
§63.10(d)(1)	General Reporting Requirements	Yes	
§63.10(d)(2)	Performance Test Results	No	This subpart requires performance test results to be reported as part of the Notification of Compliance Status due 150 days after the compliance date.
§63.10(d)(3)	Opacity or VE Observations	Yes	
§63.10(d)(4)	Progress Reports	Yes	
§63.10(d)(5)	SSM Reports	No	See §63.1575(d) for CPMS malfunction reporting and §63.1575(e) for COMS and CEMS malfunction reporting.
§63.10(e)(1)-(2)	Additional CMS Reports	Yes	Except that reports of performance evaluations must be submitted in Notification of Compliance Status.
§63.10(e)(3)	Excess Emissions/CMS Performance Reports	No	This subpart specifies the applicable requirements.
§63.10(e)(4)	COMS Data Reports	Yes	
§63.10(f)	Recordkeeping/Reporting Waiver	Yes	
§63.11(a)	Control Device and Work Practice Requirements Applicability	Yes	
§63.11(b)	Flares	Yes	Except that flares complying with §63.670 are not subject to the requirements of §63.11(b).
§63.11(c)-(e)	Alternative Work Practice for Monitoring Equipment for Leaks	Yes	
§63.12	State Authority and Delegations	Yes	
§63.13	Addresses	Yes	

Citation	Subject	Applies to subpart UUU	Explanation
§63.14	Incorporation by Reference	Yes	
§63.15	Availability of Information and Confidentiality	Yes	
§63.16	Performance Track Provisions	Yes	

[80 FR 75320, Dec. 1, 2015]

Appendix A to Subpart UUU of Part 63—Determination of Metal Concentration on Catalyst Particles (Instrumental Analyzer Procedure)

1.0 Scope and Application.

1.1 Analytes. The analytes for which this method is applicable include any elements with an atomic number between 11 (sodium) and 92 (uranium), inclusive. Specific analytes for which this method was developed include:

Analyte	CAS No.	Minimum detectable limit
Nickel compounds	7440-02-0	<2 % of span.
Total chlorides	16887-00-6	<2 % of span.

1.2 Applicability. This method is applicable to the determination of analyte concentrations on catalyst particles. This method is applicable for catalyst particles obtained from the fluid catalytic cracking unit (FCCU) regenerator (*i.e.*, equilibrium catalyst), from air pollution control systems operated for the FCCU catalyst regenerator vent (FCCU fines), from catalytic reforming units (CRU), and other processes as specified within an applicable regulation. This method is applicable only when specified within the regulation.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from the analytical method.

2.0 Summary of Method.

2.1 A representative sample of catalyst particles is collected, prepared, and analyzed for analyte concentration using either energy or wavelength dispersive X-ray fluorescent (XRF) spectrometry instrumental analyzers. In both types of XRF spectrometers, the instrument irradiates the sample with high energy (primary) x-rays and the elements in the sample absorb the x-rays and then re-emit secondary (fluorescent) x-rays of characteristic wavelengths for each element present. In energy dispersive XRF spectrometers, all secondary x-rays (of all wavelengths) enter the detector at once. The detector registers an electric current having a height proportional to the photon energy, and these pulses are then separated electronically, using a pulse analyzer. In wavelength dispersive XRF spectrometers, the secondary x-rays are dispersed spatially by crystal diffraction on the basis of wavelength. The crystal and detector are made to synchronously rotate and the detector then receives only one wavelength at a time. The intensity of the x-rays emitted by each element is proportional to its concentration, after correcting for matrix effects. For nickel compounds and total chlorides, the XRF instrument response is expected to be linear to analyte concentration. Performance specifications and test procedures are provided to ensure reliable data.

3.0 Definitions.

3.1 Measurement System. The total equipment required for the determination of analyte concentration. The measurement system consists of the following major subsystems:

3.1.1 Sample Preparation. That portion of a system used for one or more of the following: sample acquisition, sample transport, sample conditioning, or sample preparation prior to introducing the sample into the analyzer.

3.1.2 Analyzer. That portion of the system that senses the analyte to be measured and generates an output proportional to its concentration.

3.1.3 Data Recorder. A digital recorder or personal computer used for recording measurement data from the analyzer output.

3.2 Span. The upper limit of the gas concentration measurement range displayed on the data recorder.

3.3 Calibration Standards. Prepared catalyst samples or other samples of known analyte concentrations used to calibrate the analyzer and to assess calibration drift.

3.4 Energy Calibration Standard. Calibration standard, generally provided by the XRF instrument manufacturer, used for assuring accuracy of the energy scale.

3.5 Accuracy Assessment Standard. Prepared catalyst sample or other sample of known analyte concentrations used to assess analyzer accuracy error.

3.6 Zero Drift. The difference in the measurement system output reading from the initial value for zero concentration level calibration standard after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.7 Calibration Drift. The difference in the measurement system output reading from the initial value for the mid-range calibration standard after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

3.8 Spectral Interferences. Analytical interferences and excessive biases caused by elemental peak overlap, escape peak, and sum peak interferences between elements in the samples.

3.9 Calibration Curve. A graph or other systematic method of establishing the relationship between the analyzer response and the actual analyte concentration introduced to the analyzer.

3.10 Analyzer Accuracy Error. The difference in the measurement system output reading and the ideal value for the accuracy assessment standard.

4.0 Interferences.

4.1 Spectral interferences with analyte line intensity determination are accounted for within the method program. No action is required by the XRF operator once these interferences have been addressed within the method.

4.2 The X-ray production efficiency is affected by particle size for the very lightest elements. However, particulate matter (PM) 2.5 particle size effects are substantially < 1 percent for most elements. The calibration standards should be prepared with material of similar particle size or be processed (ground) to produce material of similar particle size as the catalyst samples to be analyzed. No additional correction for particle size is performed. Alternatively, the sample can be fused in order to eliminate any potential particle size effects.

5.0 Safety.

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 X-ray Exposure. The XRF uses X-rays; XRF operators should follow instrument manufacturer's guidelines to protect from accidental exposure to X-rays when the instrument is in operation.

5.3 Beryllium Window. In most XRF units, a beryllium (Be) window is present to separate the sample chamber from the X-ray tube and detector. The window is very fragile and brittle. Do not allow sample or debris to fall onto the window, and avoid using compressed air to clean the window because it will cause the window to rupture. If the window should rupture, note that Be metal is poisonous. Use extreme caution when collecting pieces of Be and consult the instrument manufacturer for advice on cleanup of the broken window and replacement.

6.0 Equipment and Supplies.

6.1 Measurement System. Use any measurement system that meets the specifications of this method listed in section 13. The typical components of the measurement system are described below.

6.1.1 Sample Mixer/Mill. Stainless steel, or equivalent to grind/mix catalyst and binders, if used, to produce uniform particle samples.

6.1.2 Sample Press/Fluxer. Stainless steel, or equivalent to produce pellets of sufficient size to fill analyzer sample window, or alternatively, a fusion device capable of preparing a fused disk of sufficient size to fill analyzer sample window.

6.1.3 Analytical Balance. ±0.0001 gram accuracy for weighing prepared samples (pellets).

6.1.4 Analyzer. An XRF spectrometer to determine the analyte concentration in the prepared sample. The analyzer must meet the applicable performance specifications in section 13.

6.1.5 Data Recorder. A digital recorder or personal computer for recording measurement data. The data recorder resolution (*i.e.*, readability) must be 0.5 percent of span. Alternatively, a digital or analog meter having a resolution of 0.5 percent of span may be used to obtain the analyzer responses and the readings may be recorded manually.

7.0 Reagents and Standards.

7.1 Calibration Standards. The calibration standards for the analyzer must be prepared catalyst samples or other material of similar particle size and matrix as the catalyst samples to be tested that have known concentrations of the analytes of interest. Preparation (grinding/milling/fusion) of the calibration standards should follow the same processes used to prepare the catalyst samples to be tested. The calibration standards values must be established as the average of a minimum of three analyses using an approved EPA or ASTM method with instrument analyzer calibrations traceable to the U.S. National Institute of Standards and Technology (NIST), if available. The maximum percent deviation of the triplicate calibration standard analyses should agree within 10 percent of the average value for the triplicate analysis (see Figure 1). If the calibration analyses do not meet this criteria, the calibration standards must be re-analyzed. If unacceptable variability persists, new calibration standards must be prepared. Approved methods for the calibration standard analyses include, but are not limited to, EPA Methods 6010B, 6020, 7520, or 7521 of SW-846.[1] Use a minimum of four calibration standards as specified below (see Figure 1):

7.1.1 High-Range Calibration Standard. Concentration equivalent to 80 to 100 percent of the span. The concentration of the high-range calibration standard should exceed the maximum concentration anticipated in the catalyst samples.

7.1.2 Mid-Range Calibration Standard. Concentration equivalent to 40 to 60 percent of the span.

7.1.3 Low-Range Calibration Standard. Concentration equivalent to 1 to 20 percent of the span. The concentration of the low-range calibration standard should be selected so that it is less than either one-fourth of the applicable concentration limit or of the lowest concentration anticipated in the catalyst samples.

7.1.4 Zero Calibration Standard. Concentration of less than 0.25 percent of the span.

7.2 Accuracy Assessment Standard. Prepare an accuracy assessment standard and determine the ideal value for the accuracy assessment standard following the same procedures used to prepare and analyze the calibration standards as described in section 7.1. The maximum percent deviation of the triplicate accuracy assessment standard analyses should agree within 10 percent of the average value for the triplicate analysis (see Figure 1). The concentration equivalent of the accuracy assessment standard must be between 20 and 80 percent of the span.

7.3 Energy Calibration Standard. Generally, the energy calibration standard will be provided by the XRF instrument manufacturer for energy dispersive spectrometers. Energy calibration is performed using the manufacturer's recommended calibration standard and involves measurement of a specific energy line (based on the metal in the energy calibration standard). This is generally an automated procedure used to assure the accuracy of the energy scale. This calibration standard may not be applicable to all models of XRF spectrometers (particularly wavelength dispersive XRF spectrometers).

8.0 Sample Collection, Preservation, Transport, and Storage. [Reserved]

9.0 Quality Control.

9.1 Energy Calibration. For energy dispersive spectrometers, conduct the energy calibration by analyzing the energy calibration standard provided by the manufacturer. The energy calibration involves measurement of a specific energy line (based on the metal in the energy calibration standard) and then determination of the difference between the measured peak energy value and the ideal value. This analysis, if applicable, should be performed daily prior to any sample analyses to check the instrument's energy scale. This is generally an automated procedure and assures the accuracy of the energy scale. If the energy scale calibration process is not automated, follow the manufacturer's procedures to manually adjust the instrument, as necessary.

9.2 Zero Drift Test. Conduct the zero drift test by analyzing the analyte concentration output by the measurement system with the initial calibration value for the zero calibration standard (see Figure 2). This analysis should be performed with each set of samples analyzed.

9.3 Calibration Drift Test. Conduct the calibration drift test by analyzing the analyte concentration output by the measurement system with the initial calibration value for the mid-range calibration standard (see Figure 2). This analysis should be performed with each set of samples analyzed.

9.4 Analyzer Accuracy Test. Conduct the analyzer accuracy test by analyzing the accuracy assessment standard and comparing the value output by the measurement system with the ideal value for the accuracy assessment standard (see Figure 2). This analysis should be performed with each set of samples analyzed.

10.0 Calibration and Standardization.

10.1 Perform the initial calibration and set-up following the instrument manufacturer's instructions. These procedures should include, at a minimum, the major steps listed in sections 10.2 and 10.3. Subsequent calibrations are to be performed when either a quality assurance/quality control (QA/QC) limit listed in section 13 is exceeded or when there is a change in the excitation conditions, such as a change in the tube, detector, X-ray filters, or signal processor. Calibrations are typically valid for 6 months to 1 year.

10.2 Instrument Calibration. Calibration is performed initially with calibration standards of similar matrix and binders, if used, as the samples to be analyzed (see Figure 1).

10.3 Reference Peak Spectra. Acquisition of reference spectra is required only during the initial calibration. As long as no processing methods have changed, these peak shape references remain valid. This procedure consists of placing the standards in the instrument and acquiring individual elemental spectra that are stored in the method file with each of the analytical conditions. These reference spectra are used in the standard deconvolution of the unknown spectra.

11.0 Analytical Procedure.

11.1 Sample Preparation. Prepare catalyst samples using the same procedure used to prepare the calibration standards. Measure and record the weight of sample used. Measure and record the amount of binder, if any, used. Pellets or films must be of sufficient size to cover the analyzer sample window.

11.2 Sample Analyses. Place the prepared catalyst samples into the analyzer. Follow the manufacturer's instructions for analyzing the samples.

11.3 Record and Store Data. Use a digital recorder or personal computer to record and store results for each sample. Record any mechanical or software problems encountered during the analysis.

12.0 Data Analysis and Calculations.

Carry out the following calculations, retaining at least one extra significant figure beyond that of the acquired data. Round off figures after final calculation.

12.1 Drift. Calculate the zero and calibration drift for the tests described in sections 9.2 and 9.3 (see also Figure 2) as follows:

$$\text{QC Value} = \frac{\mathit{CurrentAnalyzerCal}.\text{Response} - \text{InitialCal.Response}}{\text{Span}} \times 100 \qquad \text{(Eq. A-1)}$$

Where:

CurrentAnalyzerCal.Response = Instrument response for current QC sample analyses;

InitialCal.Response = Initial instrument response for calibration standard;

QC Value = QC metric (zero drift or calibration drift), percent of span;

Span = Span of the monitoring system.

12.2 Analyzer Accuracy. Calculate the analyzer accuracy error for the tests described in section 9.4 (see also Figure 2) as follows:

$$\text{Accuracy Value} = \frac{\mathit{CurrentAnalyzerCal}.\text{Response} - \text{IdealCal.Response}}{\text{IdealCal.Response}} \times 100 \qquad \text{(Eq. A-2)}$$

Where:

Accuracy Value = Percent difference of instrument response to the ideal response for the accuracy assessment standard;

CurrentAnalyzerCal.Response = Instrument response for current QC sample analyses;

IdealCal.Response = Ideal instrument response for the accuracy assessment standard.

13.0 Method Performance.

13.1 Analytical Range. The analytical range is determined by the instrument design. For this method, a portion of the analytical range is selected by choosing the span of the monitoring system. The span of the monitoring system must be selected such that it encompasses the range of concentrations anticipated to occur in the catalyst sample. If applicable, the span must be selected such that the analyte concentration equivalent to the emission standard is not less than 30 percent of the span. If the measured analyte concentration exceeds the concentration of the high-range calibration standard, the sample analysis is considered invalid. Additionally, if the measured analyte concentration is less than the concentration of the low-range calibration standard but above the detectable limit, the sample analysis results must be flagged with a footnote stating, in effect, that the analyte was detected but that the reported concentration is below the lower quantitation limit.

13.2 Minimum Detectable Limit. The minimum detectable limit depends on the signal-to-noise ratio of the measurement system. For a well-designed system, the minimum detectable limit should be less than 2 percent of the span.

13.3 Zero Drift. Less than ±2 percent of the span.

13.4 Calibration Drift. Less than ±5 percent of the span.

13.5 Analyzer Accuracy Error. Less than ±10 percent.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 Alternative Procedures. [Reserved]

17.0 References.

1. U.S. Environmental Protection Agency. 1998. Test Methods for Evaluating Solid Waste, Physical/Chemical Methods. EPA Publication No. SW-846, Revision 5 (April 1998). Office of Solid Waste, Washington, DC.

18.0 Tables, Diagrams, Flowcharts, and Validation Data.

Date:					
Analytic Method Used:					
	Zero[a]	**Low-Range**[b]	**Mid-Range**[c]	**High-Range**[d]	**Accuracy Std**[e]
Sample Run:					
1					
2					
3					
Average					
Maximum Percent Deviation					

[a] Average must be less than 0.25 percent of span.

[b] Average must be 1 to 20 percent of span.

[c] Average must be 40 to 60 percent of span.

[d] Average must be 80 to 100 percent of span.

[e] Average must be 20 to 80 percent of span.

Figure 1. Data Recording Sheet for Analysis of Calibration Samples.

Source Identification:

Run Number:

Test Personnel:

Span:

Date:

	Initial calibration response	**Current analyzer calibration response**	**Drift (percent of span)**
Zero Standard			
Mid-range Standard			
	Ideal calibration response	**Current analyzer calibration response**	**Accuracy error (percent of ideal)**
Accuracy Standard			

Figure 2. Data Recording Sheet for System Calibration Drift Data.

[70 FR 6970, Feb. 9, 2005, as amended at 80 FR 75325, Dec. 1, 2015]

Attachment Q

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on July 23, 2014]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source: 69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in §63.6675, which includes operating according to the provisions specified in §63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013]

§63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013]

§63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

Emission and Operating Limitations

§63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

§63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in §63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in §63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in §63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in §63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in §63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013]

§63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2), or are on offshore vessels that meet §63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013]

General Compliance Requirements

§63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

Testing and Initial Compliance Requirements

§63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

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

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209\ F_d}{F_c} \quad (Eq.\ 2)$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm3/J (dscf/106 Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm3/J (dscf/106 Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO2} = \frac{5.9}{F_O} \quad (Eq. 3)$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2—15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq. 4)$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013]

§63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR

part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet §63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013]

§63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

Continuous Compliance Requirements

§63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE 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.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013]

Notifications, Reports, and Records

§63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in §63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in §63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013]

§63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 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 your source in §63.6595.

(2) For semiannual Compliance reports, 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 your affected source in §63.6595.

(3) For semiannual Compliance reports, 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) For semiannual Compliance reports, 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 stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 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 (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(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 you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred 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.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, 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 into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 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 7 of 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 or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

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

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in §63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in §63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in §63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §63.13.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013]

§63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) 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 that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

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

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

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in §63.6640(f)(2)(ii) or (iii) or §63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013]

§63.6660 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 §63.10(b)(1).

(b) As specified in §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 readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. 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 U.S. EPA Regional Office to find out whether 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 contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

§63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see §63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) 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

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §63.6640(f)(2)(ii) or (iii) and §63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013]

Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR.	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2 until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and
	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2.	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2.	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2.	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2.	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2.	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]

Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	

For each . . .	**You must meet the following requirement, except during periods of startup . . .**	**During periods of startup you must . . .**
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]; b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE.	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1] Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[78 FR 6709, Jan. 30, 2013]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

[1] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. reduce CO emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For CO and O_2 measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure the O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[ac] (heated probe not necessary)	(b) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		iii. Measure the CO at the inlet and the outlet of the control device	(1) ASTM D6522-00 (Reapproved 2005)[abc] (heated probe not necessary) or Method 10 of 40 CFR part 60, appendix A-4	(c) The CO concentration must be at 15 percent O_2, dry basis.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
2. 4SRB stationary RICE	a. reduce formaldehyde emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For formaldehyde, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[a] (heated probe not necessary)	(a) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03[a]	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03[a], provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A-7	(a) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
3. Stationary RICE	a. limit the concentra-tion of formalde-hyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and		(a) For formaldehyde, CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A. If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[a] (heated probe not necessary)	(a) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the station-ary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03[a]	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iv. Measure formalde-hyde at the exhaust of the station-ary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03[a], provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. measure CO at the exhaust of the station-ary RICE	(1) Method 10 of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (2005)[ac], Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03[a]	(a) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[a] You may also use Methods 3A and 10 as options to ASTM-D6522-00 (2005). You may obtain a copy of ASTM-D6522-00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[b] You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[79 FR 11290, Feb. 27, 2014]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

[78 FR 6712, Jan. 30, 2013]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.

For each . . .	**Complying with the requirement to . . .**	**You must demonstrate continuous compliance by . . .**
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent $O_{2,}$ or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6715, Jan. 30, 2013]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in §63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or	i. Semiannually according to the requirements in §63.6650(b).
		c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4).	i. Semiannually according to the requirements in §63.6650(b).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in §63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in §63.6650(b)(1)-(5).

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in §63.6640(f)(4)(ii)	Report	a. The information in §63.6650(h)(1)	i. annually according to the requirements in §63.6650(h)(2)-(3).

[78 FR 6719, Jan. 30, 2013]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)-(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)-(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)-(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	No	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§63.8(c)(2)-(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
		Except that §63.8(e) only applies as specified in §63.6645.	
§63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)-(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.
§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	
§63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§63.10(b)(2)(i)-(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)-(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)-(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i) (C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010, as amended at 78 FR 6720, Jan. 30, 2013]

Appendix A—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 Scope and Application. What is this Protocol?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782-44-7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 Summary of Protocol

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 Definitions

3.1 Measurement System. The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:

3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 Interferences.

When present in sufficient concentrations, NO and NO_2 are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 Safety. [Reserved]

6.0 Equipment and Supplies.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 Reagents and Standards. What calibration gases are needed?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ±5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O_2 Calibration Gas Concentration.

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2. When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).

8.0 Sample Collection and Analysis

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the “measurement data phase” readings to calculate the average stack gas CO and O_2 concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ±10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ±3 percent, as instructed by the EC cell manufacturer.

9.0 Quality Control (Reserved)

10.0 Calibration and Standardization

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ±3 percent of the up-scale gas value or ±1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ±0.3 percent O_2 for the O_2 channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this "sample conditioning phase" once per minute until readings are constant for at least two minutes. Then begin the "measurement data phase" and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the "measurement data phase" readings from the reported standard gas value must be less than or equal to ±5 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single "measurement data phase" reading must be less than or equal to ±2 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the "measurement data phase".

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the "measurement data phase". The maximum allowable deviation from the mean for each of the individual readings is ±2 percent, or ±1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ±2 percent *or* ±1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed).

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO_2 interference response should be less than or equal to ±5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average “measurement data phase” CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ±3 percent or ±1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References

(1) “Development of an Electrochemical Cell Emission Analyzer Test Protocol”, Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) “Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers”, EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) “ICAC Test Protocol for Periodic Monitoring”, EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) “Code of Federal Regulations”, Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

Table 1: Appendix A—Sampling Run Data.

Facility___________ Engine I.D.___________ Date______											
Run Type:	(_)				(_)			(_)			(_)
(X)	Pre-Sample Calibration				Stack Gas Sample			Post-Sample Cal. Check			Repeatability Check
Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO			
Sample Cond. Phase											
″											
″											
″											
″											
Measurement Data Phase											
″											
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″											
″											
Mean											
Refresh Phase											
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″											

[78 FR 6721, Jan. 30, 2013]

Attachment R

Part 70 Operating Permit No: 147-39554-00065

[Downloaded from the eCFR on November 25, 2015]

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Source: 76 FR 15664, Mar. 21, 2011, unless otherwise noted.

What This Subpart Covers

§63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations 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, except as specified in §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575.

[78 FR 7162, Jan. 31, 2013]

§63.7490 What is the affected source of this subpart?

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

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

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, 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 June 4, 2010, 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.

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

§63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part or a natural gas-fired EGU as defined in subpart UUUUU of this part firing at least 85 percent natural gas on an annual heat input basis.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see §63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

(j) Temporary boilers and process heaters as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler or process heater specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in §63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72806, Nov. 20, 2015]

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

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in §63.6(i).

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(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.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in §63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of §60.2145(a)(2) and (3) or §60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2016, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in §63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

(h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after the compliance date of this subpart, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.

(i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

Emission Limitations and Work Practice Standards

§63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in §63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

§63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under §63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate either steam, cogenerate steam with electricity, or both. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate only electricity. Boilers that perform multiple functions (cogeneration and electricity generation) or supply steam to common headers would calculate a total steam energy output using equation 21 of §63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction on or after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction on or after December 23, 2011 and before April 1, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

(2) You must meet each operating limit in Table 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 Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under §63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in §63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

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

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in §63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in §63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with items 5 and 6 of Table 3 to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

§63.7501 [Reserved]

General Compliance Requirements

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

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These emission and operating limits apply to you at all times the affected unit is operating except for the periods noted in §63.7500(f).

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to §63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance stack testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits through the use of CPMS, or with a CEMS or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under §63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in §63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of §63.7525. Using the process described in §63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

(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, accuracy audits, analytical drift).

(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)(ii), (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) (as applicable in Table 10 to this subpart), (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, and you choose to comply using definition (2) of “startup” in §63.7575, you must develop and implement a written startup and shutdown plan (SSP) according to the requirements in Table 3 to this subpart. The SSP must be maintained onsite and available upon request for public inspection.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7164, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

Testing, Fuel Analyses, and Initial Compliance Requirements

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

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance (stack) testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to §63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under §63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those Gas 1 fuels according to §63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those non-Gas 1 gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those non-Gas 1 fuels according to §63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to §63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to §63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart 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 §63.7521 and Table 6 to this subpart and establish operating limits according to §63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to §63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, as specified in §63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with §63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in §63.7490), you must complete the initial compliance demonstrations, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than the compliance date specified in §63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in §63.7495.

(f) For new or reconstructed affected sources (as defined in §63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

(g) For new or reconstructed affected sources (as defined in §63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in §63.7515(d) following the initial compliance date specified in §63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in §63.7515(d).

(h) For affected sources (as defined in §63.7490) that ceased burning solid waste consistent with §63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2016, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in §63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in §63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in §63.7495.

(k) For affected sources, as defined in §63.7490, that switch subcategories consistent with §63.7545(h) after the initial compliance date, you must demonstrate compliance within 60 days of the effective date of the switch, unless you had previously conducted your compliance demonstration for this subcategory within the previous 12 months.

[78 FR 7164, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015]

§63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to §63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under §63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to §63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in §63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to §63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. 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 §63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level. If sampling is conducted on one day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply.

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

(g) For affected sources (as defined in §63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) and the schedule described in §63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra-low sulfur liquid fuel, you do not need to conduct further performance tests (stack tests or fuel analyses) if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra-low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in §63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in §63.7510(a).

[78 FR 7165, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015]

§63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to §63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in §63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

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

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

(e) 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 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7166, Jan. 31, 2013]

§63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in §63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in §63.7510.

(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 anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated 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 anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of 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 you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(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) You must obtain composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material. At a minimum, for demonstrating initial compliance by fuel analysis, you must obtain three composite samples. For monthly fuel analyses, at a minimum, you must obtain a single composite sample. For fuel analyses as part of a performance stack test, as specified in §63.7510(a), you must obtain a composite fuel sample during each performance test run.

(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. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing.

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

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

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

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

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

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

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

(4) You must separate one of the quarter samples as the first subset.

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

(6) You must grind the sample in a mill.

(7) You must 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) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) 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, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in §63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section, or as an alternative where fuel specification analysis is not practical, you must measure mercury concentration in the exhaust gas when firing only the gaseous fuel to be demonstrated as an other gas 1 fuel in the boiler or process heater according to the procedures in Table 6 to this subpart.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop a site-specific fuel analysis plan for other gas 1 fuels according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in §63.7510.

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

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

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

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. 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. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of 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 you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(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. When using a fuel supplier's fuel analysis, the owner or operator is not required to submit the information in §63.7521(g)(2)(iii).

(h) You must obtain a single fuel sample for each fuel type for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

[78 FR 7167, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015]

§63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of §63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on April 1, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on April 1, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 to this subpart at all times the affected units are subject to numeric emission limits following the compliance date specified in §63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1a or 1b or 1c of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Hm \right) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq.1a)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times So \right) \div \sum_{i=1}^{n} So \qquad \text{(Eq.1b)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c). If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, Eadj, determined according to §63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Eo \right) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq.1c)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c). If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, Eadj, determined according to §63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1a of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart that are in pounds per million Btu of heat input.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Sm \times Cfi \right) \div \sum_{i=1}^{n} \left(Sm \times Cfi \right) \qquad \text{(Eq. 2)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.

Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in §63.7495. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual electrical generation for the month if you are complying with the emission limits on an electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Hb \right) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3a)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Hb = The heat input for that calendar month to unit, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times So \right) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 3b)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to §63.7533 for that unit.

So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Eo\right) \div \sum_{i=1}^{n} Eo \quad \text{(Eq. 3c)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to §63.7533 for that unit.

Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Sa \times Cfi\right) \div \sum_{i=1}^{n} \left(Sa \times Cfi\right) \quad \text{(Eq. 4)}$$

Where:

AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.

$$Eavg = \sum_{i=1}^{n} ERi \div 12 \quad \text{(Eq. 5)}$$

Where:

Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)

ERi = Monthly weighted average, for calendar month “i” (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(1) If requested, you must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of PM (or TSM), HCl, or mercury emissions in accordance with the requirements in §63.7520;

(v) The operating parameters to be monitored for each control system or device consistent with §63.7500 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to §63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) If submitted upon request, the Administrator shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing unit in the same subcategories.

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in §63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En = \sum_{i=1}^{n}(ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu) or parts per million (ppm).

Eli = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu or ppm.

Hi = Heat input from unit i, MMBtu.

(2) Conduct performance tests according to procedures specified in §63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in §63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7168, Jan. 31, 2013; 80 FR 72809, Nov. 20, 2015]

§63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in §63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen (or carbon dioxide (CO_2)) according to the procedures in paragraphs (a)(1) through (6) of this section.

(1) Install the CO CEMS and oxygen (or CO_2) analyzer by the compliance date specified in §63.7495. The CO and oxygen (or CO_2) levels shall be monitored at the same location at the outlet of the boiler or process heater. An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the CO emissions limit be determined using CO_2 as a diluent correction in place of oxygen at 3 percent. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3 percent oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B; part 75 of this chapter (if an CO_2 analyzer is used); the site-specific monitoring plan developed according to §63.7505(d); and the requirements in §63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to §63.7505(d), and the requirements in §63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in §63.8(e) and according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must be collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with §63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(vi) When CO_2 is used to correct CO emissions and CO_2 is measured on a wet basis, correct for moisture as follows: Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO concentrations. The following continuous moisture monitoring systems are acceptable: A continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O_2 both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, *i.e.,* a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (*e.g.,* hourly average wet-and dry basis O_2 values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

(3) Complete a minimum of one cycle of CO and oxygen (or CO_2) CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen (or CO_2) data concurrently. Collect at least four CO and oxygen (or CO_2) CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in §63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen (or corrected to an CO_2 percentage determined to be equivalent to 3 percent oxygen) from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in §63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in §63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in §63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (*e.g.,* bag leak detectors, ESP secondary power, and PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must have a documented detection limit of 0.5 milligram per actual cubic meter, or less.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of §60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in §63.7495.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter.

(2) You must conduct a performance evaluation of each COMS according to the requirements in §63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

(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) You must include in your 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) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of §63.8(e). You must 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. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

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

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in §63.7495.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in §63.7535(b), and comply with the data calculation requirements specified in §63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in §63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in §63.7535(c).

(5) You must record the results of each inspection, calibration, and validation check.

(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

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

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (*e.g.*, PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (*e.g.*, check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in you monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install 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) Calibrate the pH monitoring system in accordance with your monitoring plan and according to the manufacturer's instructions. Clean the pH probe at least once each process operating day. Maintain on-site documentation that your calibration frequency is sufficient to maintain the specified accuracy of your device.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see §63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

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

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in §63.7540(a)(14) for a mercury CEMS and §63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A-7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM,

mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide (SO_2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you elect to use an SO_2 CEMS to demonstrate continuous compliance with the HCl emission limit, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to either part 60 or part 75 of this chapter.

(1) The SO_2 CEMS must be installed by the compliance date specified in §63.7495.

(2) For on-going quality assurance (QA), the SO_2 CEMS must meet either the applicable daily and quarterly requirements in Procedure 1 of appendix F of part 60 or the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO_2 data, you must operate the SO_2 CEMS as specified in §63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in §63.7535(c). Periods when SO_2 data are unavailable may constitute monitoring deviations as specified in §63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7171, Jan. 31, 2013; 80 FR 72810, Nov. 20, 2015]

§63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to §63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by §63.7510(a)(2). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to §63.7525.

(b) If you demonstrate compliance through performance stack testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in §63.7510(a)(2). (Note that §63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(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 fuel analysis for hydrogen chloride, 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 7 of this section.

$$Clinput = \sum_{i=1}^{n} (Ci \times Qi) \quad \text{(Eq. 7)}$$

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 §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 during the initial compliance test. 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(2)(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 mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \quad \text{(Eq. 8)}$$

Where:

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

HGi = Arithmetic average concentration of mercury in fuel type, i, analyzed according to §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 mercury content during the initial compliance test. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(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 TSM.

(ii) During the fuel analysis for TSM, 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 TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^{n} (TSMi \times Qi) \qquad \text{(Eq. 9)}$$

Where:

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

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to §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 TSM during the initial compliance test. 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in §63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, 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 flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(*1*) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(*2*) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(*3*) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(*1*) through (*4*) of this section.

(*1*) Determine your instrument zero output with one of the following procedures:

(*i*) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*ii*) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*iii*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*iv*) If none of the steps in paragraphs (b)(4)(ii)(B)(*1*)(*i*) through (*iii*) of this section are possible, you must use a zero output value provided by the manufacturer.

(*2*) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

Where:

X_1 = the PM CPMS data points for the three runs constituting the performance test,

Y_1 = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$\mathrm{R} = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 11)}$$

Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 12)}$$

Where:

O_l = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 13)}$$

Where:

X_1 = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(D) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30-\text{day} = \frac{\sum_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 14)}$$

Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 30 operating days.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers (“back half”) of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the “back half” for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (*e.g.* beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in §63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate 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 flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iv) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(v) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

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

(viii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(ix) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO_2 CEMS is to install and operate the SO_2 according to the requirements in §63.7525(m) establish a maximum SO_2 emission rate equal to the highest hourly average SO_2 measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to §63.7521 and follow the procedures in paragraphs (c)(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 t-statistic test described in Equation 15 of this section.

$$P90 = mean + (SD \times t) \qquad \text{(Eq. 15)}$$

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 §63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-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 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} \left(Ci90 \times Qi \times 1.028 \right) \qquad \text{(Eq. 16)}$$

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 15 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} \left(Hgi90 \times Qi \right) \qquad \text{(Eq. 17)}$$

Where:

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

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$Metals = \sum_{i=1}^{n} \left(TSM90i \times Qi \right) \qquad \text{(Eq. 18)}$$

Where:

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

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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

(d)[Reserved]

(e) You must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 to this subpart, and that the assessment is an accurate depiction of your facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

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

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in §63.7575, you must conduct an initial fuel specification analyses according to §63.7521(f) through (i) and according to the frequency listed in §63.7540(c) and maintain records of the results of the testing as outlined in §63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO_2 CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO_2 CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with §63.7500(a)(3); and

(3) You establish a unit-specific maximum SO_2 operating limit by collecting the maximum hourly SO_2 emission rate on the SO_2 CEMS during the paired 3-run test for HCl. The maximum SO_2 operating limit is equal to the highest hourly average SO_2 concentration measured during the HCl performance test.

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§63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to §63.7522(e) and for demonstrating monthly compliance according to §63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: *http://www.epa.gov/ttn/atw/boiler/boilerpg.html.*

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.,* fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual} \right) \div EI_{baseline} \qquad \text{(Eq. 19)}$$

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is subject to numeric emission limits, following the compliance date specified in §63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_{m} \times (1 - ECredits) \qquad \text{(Eq. 20)}$$

Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under §63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7178, Jan. 31, 2013; 80 FR 72812, Nov. 20, 2015]

Continuous Compliance Requirements

§63.7535 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.7505(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see §63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during periods of startup and shutdown, monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods of startup and shutdown, when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your semi-annual report.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7179, Jan. 31, 2013; 80 FR 72812, Nov. 20, 2015]

§63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in §63.7555(d), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Equal to or lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Equal to or lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 16 of §63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 16 of §63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of §63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of §63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in §63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 17 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 17 of §63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using

Equation 8 of §63.7530. If the results of recalculating the maximum mercury input using Equation 8 of §63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is subject to numeric emission limits.

(iii) Keep records of CO levels according to §63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in §63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited-use boilers and process heaters, as defined in §63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in §63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for mercury CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for mercury CEMS. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for HCl CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for HCl CEMS. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of §63.7530. If the results of recalculating the maximum TSM input using Equation 9 of §63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 18 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 18 of §63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the

CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2— Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (v) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in §63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in §63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in §63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in §63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in §63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in §63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to items 5 and 6 of Table 3 of this subpart.

[78 FR 7179, Jan. 31, 2013, as amended at 80 FR 72813, Nov. 20, 2015]

§63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.7522(f) and (g).

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7182, Jan. 31, 2013]

Notification, Reports, and Records

§63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator 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 to you by the dates specified.

(b) As specified in §63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in §63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, 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 60 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, 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 all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as applicable. If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8) of this section and must be submitted within 60 days of the compliance date specified at §63.7495(b).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under §241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of §241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

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

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(iii) Identification of whether you are complying the arithmetic mean of all valid hours of data from the previous 30 operating days or of the previous 720 hours. This identification shall be specified separately for each operating parameter.

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

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

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

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

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, 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.

(8) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) “This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in §63.7540(a)(10)(i) through (vi).”

(ii) “This facility has had an energy assessment performed according to §63.7530(e).”

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: “No secondary materials that are solid waste were combusted in any affected unit.”

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in §63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in paragraphs (f)(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.

(g) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(h) If you have switched fuels or made a physical change to the boiler or process heater and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date upon which the fuel switch or physical change occurred.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7183, Jan. 31, 2013; 80 FR 72814, Nov. 20, 2015]

§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 §63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct subsequent annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first semi-annual compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater 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 your source in §63.7495. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in §63.7495.

(2) The first semi-annual compliance report must be postmarked or submitted 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 each boiler or process heater in §63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent semi-annual 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. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

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

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.

(2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

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

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with §63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of §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 16 of §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 and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of §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 17 of §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). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of §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 18 of §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).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of §63.7530 or the maximum mercury input operating limit using Equation 8 of §63.7530, or the maximum TSM input operating limit using Equation 9 of §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.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in §63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with §63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in §63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values for CEMS (CO, HCl, SO_2, and mercury), 10 day rolling average values for CO CEMS when the limit is expressed as a 10 day instead of 30 day rolling average, and the PM CPMS data.

(xvii) 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.

(xviii) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of §63.7555(d).

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, or from the work practice standards for periods if startup and shutdown, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

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

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

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in §63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (as defined in §63.2) required by this subpart, you must submit the results of the performance tests, including any fuel analyses, following the procedure specified in either paragraph (h)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*), you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation (as defined in 63.2), you must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being transmitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in §63.13.

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

[78 FR 7183, Jan. 31, 2013, as amended at 80 FR 72814, Nov. 20, 2015]

§63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) 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 §63.10(b)(2)(xiv).

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

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2)(vii) 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.

(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, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) 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.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to §241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under §241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to §241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in §241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under §241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per §241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under §241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 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 16 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. 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.

(4) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 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 17 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. 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.

(5) If, consistent with §63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

(6) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment.

(7) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in §63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(8) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 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 18 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. 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 TSM fuel input, or TSM emission rates, for each boiler and process heater.

(9) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(10) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(11) For each startup period, for units selecting paragraph (2) of the definition of “startup” in §63.7575 you must maintain records of the time that clean fuel combustion begins; the time when you start feeding fuels that are not clean fuels; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged.

(12) If you choose to rely on paragraph (2) of the definition of “startup” in §63.7575, for each startup period, you must maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and all hourly average CMS data (*e.g.,* CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged. In addition, if compliance with the PM emission limit is demonstrated using a PM control device, you must maintain records as specified in paragraphs (d)(12)(i) through (iii) of this section.

(i) For a boiler or process heater with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(ii) For a boiler or process heater with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(iii) For a boiler or process heater with a wet scrubber needed for filterable PM control, record the scrubber's liquid flow rate and the pressure drop during each hour of startup.

(13) If you choose to use paragraph (2) of the definition of “startup” in §63.7575 and you find that you are unable to safely engage and operate your PM control(s) within 1 hour of first firing of non-clean fuels, you may choose to rely on paragraph (1) of definition of “startup” in §63.7575 or you may submit to the delegated permitting authority a request for a variance with the PM controls requirement, as described below.

(i) The request shall provide evidence of a documented manufacturer-identified safety issue.

(ii) The request shall provide information to document that the PM control device is adequately designed and sized to meet the applicable PM emission limit.

(iii) In addition, the request shall contain documentation that:

(A) The unit is using clean fuels to the maximum extent possible to bring the unit and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel;

(B) The unit has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) Identifies with specificity the details of the manufacturer's statement of concern.

(iv) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

(e) If you elect to average emissions consistent with §63.7522, you must additionally keep a copy of the emission averaging implementation plan required in §63.7522(g), all calculations required under §63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with §63.7541.

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to §63.7533, you must keep a copy of the Implementation Plan required in §63.7533(d) and copies of all data and calculations used to establish credits according to §63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by §63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7185, Jan. 31, 2013; 80 FR 72816, Nov. 20, 2015]

§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 §63.10(b)(1).

(b) As specified in §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, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or an Administrator 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 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 (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission limits and work practice standards in §63.7500(a) and (b) under §63.6(g), except as specified in §63.7555(d)(13).

(2) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90, and alternative analytical methods requested under §63.7521(b)(2).

(3) Approval of major change to monitoring under §63.8(f) and as defined in §63.90, and approval of alternative operating parameters under §§63.7500(a)(2) and 63.7522(g)(2).

(4) Approval of major change to recordkeeping and reporting under §63.10(e) and as defined in §63.90.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7186, Jan. 31, 2013; 80 FR 72817, Nov. 20, 2015]

§63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in §63.2 (the General Provisions), and in this section as follows:

10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid CO CEMS data. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent. For parameters other than CO, 30-day rolling average means either the arithmetic mean of all valid hours of data from 30 successive operating days or the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating.

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.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are 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.

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see §63.14).

Biomass or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; wood products (*e.g.,* trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; 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. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

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 annual gas volume 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. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Clean dry biomass means any biomass-based solid fuel that have not been painted, pigment-stained, or pressure treated, does not contain contaminants at concentrations not normally associated with virgin biomass materials and has a moisture content of less than 20 percent and is not a solid waste.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see §63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of “coal” includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. 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, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

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 applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(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.

(2) A deviation is not always a violation.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see §60.14).

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 used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) 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 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be “capable of combusting” fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (*e.g.,* steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

(2) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 33 percent of the energy (*e.g.,* steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (*e.g.,* steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (*e.g.,* product X manufacturing area; product Y drying area; Building Z).

Energy management practices means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an “as received” basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

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. A fabric filter is a dry control system.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, 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 boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are 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, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

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, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis as demonstrated by monthly fuel analysis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Light liquid includes distillate oil, biodiesel, or vegetable oil.

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, and vegetable oil.

Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (*e.g.,* for 50 percent load the load fraction is 0.5). For boilers and process heaters that co-fire natural gas or refinery gas with a solid or liquid fuel, the load fraction is determined by the actual heat input of the solid or liquid fuel divided by heat input of the solid or liquid fuel fired during the performance test (*e.g.,* if the performance test was conducted at 100 percent solid fuel firing, for 100 percent load firing 50 percent solid fuel and 50 percent natural gas the load fraction is 0.5).

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum pressure drop means the lowest hourly 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 the lowest hourly average sorbent liquid pH measured at the inlet to 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 liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion not using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current 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) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see §63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period. For calculating rolling average emissions, an operating day does not include the hours of operation during startup or shutdown.

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device over its operating load range. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller or draft controller.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Process heater means an enclosed device using controlled flame, 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 (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in §241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

Pulverized coal boiler means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Regulated gas stream means an offgas stream that is routed to a boiler or process heater for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

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 of Testing and Materials in ASTM D396-10 (incorporated by reference, *see* §63.14(b)).

Responsible official means responsible official as defined in §70.2.

Rolling average means the average of all data collected during the applicable averaging period. For demonstration of compliance with a CO CEMS-based emission limit based on CO concentration a 30-day (10-day) rolling average is comprised of the average of all the hourly average concentrations over the previous 720 (240) operating hours calculated each operating day. To demonstrate compliance on a 30-day rolling average basis for parameters other than CO, you must indicate the basis of the 30-day rolling average period you are using for compliance, as discussed in §63.7545(e)(2)(iii). If you indicate the 30 operating day basis, you must calculate a new average value each operating day and shall include the measured hourly values for the preceding 30 operating days. If you select the 720 operating hours basis, you must average of all the hourly average concentrations over the previous 720 operating hours calculated each operating day.

Secondary material means the material as defined in §241.2 of this chapter.

Shutdown means the period in which cessation of operation of a boiler or process heater is initiated for any purpose. Shutdown begins when the boiler or process heater no longer supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes and/or generates electricity or when no fuel is being fed to the boiler or process heater, whichever is earlier. Shutdown ends when the boiler or process heater no longer supplies useful thermal energy (such as steam or heat) for heating, cooling, or process purposes and/or generates electricity, and no fuel is being combusted in the boiler or process heater.

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Startup means:

(1) Either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the useful thermal energy from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose, or

(2) The period in which operation of a boiler or process heater is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy (such as steam or heat) for heating, cooling or process purposes, or producing electricity, or the firing of fuel in a boiler or process heater for any purpose after a shutdown event. Startup ends four hours after when the boiler or process heater supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes, or generates electricity, whichever is earlier.

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be the appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input (lb per MWh).

(4) For a boiler that performs multiple functions and produces steam to be used for any combination of paragraphs (1), (2), and (3) of this definition that includes electricity generation of paragraph (3) of this definition, the total energy output, in terms of MMBtu of steam output, is the sum of the energy content of steam sent directly to the process and/or used for heating (S_1), the energy content of turbine steam sent to process plus energy in electricity according to paragraph (2) of this definition (S_2), and the energy content of electricity generated by a electricity only turbine as paragraph (3) of this definition ($MW_{(3)}$) and would be calculated using Equation 21 of this section. In the case of boilers supplying steam to one or more common heaters, S_1, S_2, and $MW_{(3)}$ for each boiler would be calculated based on the its (steam energy) contribution (fraction of total steam energy) to the common heater.

$$SO_M = S_1 + S_2 + (MW_{(3)}\ x\ CFn) \qquad \text{(Eq. 21)}$$

Where:

SO_M = Total steam output for multi-function boiler, MMBtu

S_1 = Energy content of steam sent directly to the process and/or used for heating, MMBtu

S_2 = Energy content of turbine steam sent to the process plus energy in electricity according to (2) above, MMBtu

$MW_{(3)}$ = Electricity generated according to paragraph (3) of this definition, MWh

CFn = Conversion factor for the appropriate subcategory for converting electricity generated according to paragraph (3) of this definition to equivalent steam energy, MMBtu/MWh

CFn for emission limits for boilers in the unit designed to burn solid fuel subcategory = 10.8

CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal = 11.7

CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass = 12.1

CFn for emission limits for boilers in one of the subcategories of units designed to burn liquid fuel = 11.2

CFn for emission limits for boilers in the unit designed to burn gas 2 (other) subcategory = 6.2

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler or process heater that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler or process heater is not a temporary boiler or process heater if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or process heater or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler or process heater that replaces a temporary boiler or process heater at a location and performs the same or similar function will be included in calculating the consecutive time period.

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

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, process heat, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Traditional fuel means the fuel as defined in §241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in §63.7540(a)(10).

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Useful thermal energy means energy (*i.e.,* steam, hot water, or process heat) that meets the minimum operating temperature, flow, and/or pressure required by any energy use system that uses energy provided by the affected boiler or process heater.

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards or VCS mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, *http://www.astm.org*), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, *http://www.asme.org*), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211

Geneva 20, Switzerland, + 41 22 749 01 11, *http://www.iso.org/iso/home.htm*), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 *http://www.stadards.org.au*), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, + 44 (0)20 8996 9001, *http://www.bsigroup.com*), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, *http://www.csa.ca*), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium + 32 2 550 08 11, *http://www.cen.eu/cen*), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, + 49 211 6214-230, *http://www.vdi.eu*). The types of standards that are not considered VCS are standards developed by: The United States, *e.g.,* California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.,* Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Waste heat process heater means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

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 or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

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 Clean Air Act.

[78 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72817, Nov. 20, 2015]

Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters

As stated in §63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.28 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. Mercury	8.0E-07[a] lb per MMBtu of heat input	8.7E-07[a] lb per MMBtu of steam output or 1.1E-05[a] lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (4.2E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05[a] lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04[a] lb per MMBtu of steam output or 1.2E-03[a] lb per MWh)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 10-day rolling average)	3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	4.3E-03 lb per MMBtu of steam output or 4.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1.1 lb per MMBtu of steam output or 1.0E + 01 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05[a] lb per MMBtu of heat input)	3.0E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[d] 30-day rolling average)	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	4.8E-04 lb per MMBtu of steam output or 6.1E-03 lb per MWh	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. Mercury	4.8E-07[a] lb per MMBtu of heat input	5.3E-07[a] lb per MMBtu of steam output or 6.7E-06[a] lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	1.5E-02 lb per MMBtu of steam output or 1.8E-01 lb per MWh; or (8.2E-05 lb per MMBtu of steam output or 1.1E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03[a] lb per MMBtu of steam output or 1.6E-02[a] lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provisions of §63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see §63.14.

[c] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before April 1, 2013, you may comply with the emission limits in Tables 11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

[d] An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[78 FR 7193, Jan. 31, 2013, as amended at 80 FR 72819, Nov. 20, 2015]

Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters

As stated in §63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.7E-06 lb per MMBtu of heat input	6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	4.0E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 4.9E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,^{c} 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen,^{c} 30-day rolling average)	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)	4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,^{c} 30-day rolling average)	4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input)	1.4E-01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E-03 lb per MMBtu of steam output or 1.7E-02 lb per MWh)	Collect a minimum of 1 dscm per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
10. Suspension burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	5.2E-02 lb per MMBtu of steam output or 7.1E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)	3.9E-01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid	a. CO	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen	2.4 lb per MMBtu of steam output or 12 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)	5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	a. CO (or CEMS)	3,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	3.5 lb per MMBtu of steam output or 39 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E-06[a] lb per MMBtu of heat input	2.5E-06[a] lb per MMBtu of steam output or 2.8E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784,[b] collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.5E-02 lb per MMBtu of steam output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03[a] lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03[a] lb per MMBtu of steam output or 1.1E-01[a] lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provisions of §63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see §63.14.

[c] An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[78 FR 7195, Jan. 31, 2013, as amended at 80 FR 72821, Nov. 20, 2015]

Table 3 to Subpart DDDDD of Part 63—Work Practice Standards

As stated in §63.7500, you must comply with the following applicable work practice standards:

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater	Conduct a tune-up of the boiler or process heater every 5 years as specified in §63.7540.
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid	Conduct a tune-up of the boiler or process heater biennially as specified in §63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater	Conduct a tune-up of the boiler or process heater annually as specified in §63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in §63.7495 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in §63.7575:
	a. A visual inspection of the boiler or process heater system.
	b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.
	c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.

If your unit is . . .	You must meet the following . . .
	d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
	e. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified.
	f. A list of cost-effective energy conservation measures that are within the facility's control.
	g. A list of the energy savings potential of the energy conservation measures identified.
	h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup	a. You must operate all CMS during startup. b. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, clean dry biomass, and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis. c. You have the option of complying using either of the following work practice standards. (1) If you choose to comply using definition (1) of “startup” in §63.7575, once you start firing fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose, OR (2) If you choose to comply using definition (2) of “startup” in §63.7575, once you start to feed fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must engage and operate PM control within one hour of first feeding fuels that are not clean fuels[a]. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in §63.7505(e). d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet this work practice. You must collect monitoring data during periods of startup, as specified in §63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in §63.7555.

If your unit is . . .	**You must meet the following . . .**
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown	You must operate all CMS during shutdown. While firing fuels that are not clean fuels during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control device. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas. You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in §63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in §63.7555.

[a]As specified in §63.7555(d)(13), the source may request an alternative timeframe with the PM controls requirement to the permitting authority (state, local, or tribal agency) that has been delegated authority for this subpart by EPA. The source must provide evidence that (1) it is unable to safely engage and operate the PM control(s) to meet the "fuel firing + 1 hour" requirement and (2) the PM control device is appropriately designed and sized to meet the filterable PM emission limit. It is acknowledged that there may be another control device that has been installed other than ESP that provides additional PM control (*e.g.*, scrubber).

[78 FR 7198, Jan. 31, 2013, as amended at 80 FR 72823, Nov. 20, 2015]

Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

As stated in §63.7500, you must comply with the applicable operating limits:

Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	**You must meet these operating limits . . .**
1. Wet PM scrubber control on a boiler or process heater not using a PM CPMS	Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the performance test demonstrating compliance with the PM emission limitation according to §63.7530(b) and Table 7 to this subpart.
2. Wet acid gas (HCl) scrubber[a] control on a boiler or process heater not using a HCl CEMS	Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the performance test demonstrating compliance with the HCl emission limitation according to §63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on a boiler or process heater not using a PM CPMS	a. Maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average); or

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	**You must meet these operating limits . . .**
	b. Install and operate a bag leak detection system according to §63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control on a boiler or process heater not using a PM CPMS	a. This option is for boilers and process heaters that operate dry control systems (*i.e.*, an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (*i.e.*, dry ESP). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control on a boiler or process heater not using a mercury CEMS	Maintain the minimum sorbent or carbon injection rate as defined in §63.7575 of this subpart.
6. Any other add-on air pollution control type on a boiler or process heater not using a PM CPMS	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
7. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.
8. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2 analyzer system as specified in §63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.7525(a).
9. SO_2 CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2 CEMS, maintain the 30-day rolling average SO_2 emission rate at or below the highest hourly average SO_2 concentration measured during the HCl performance test, as specified in Table 8.

[a] A wet acid gas scrubber is a control device that removes acid gases by contacting the combustion gas with an alkaline slurry or solution. Alkaline reagents include, but not limited to, lime, limestone and sodium.

[80 FR 72874, Nov. 20, 2015]

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 testing for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant . . .	You must. . .	Using, as appropriate . . .
1. Filterable PM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
2. TSM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the TSM emission concentration	Method 29 at 40 CFR part 60, appendix A-8 of this chapter
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]

To conduct a performance test for the following pollutant . . .	**You must. . .**	**Using, as appropriate . . .**
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the hydrogen chloride emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981.[a]
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

[a] Incorporated by reference, see §63.14.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7200, Jan. 31, 2013; 80 FR 72825, Nov. 20, 2015]

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. However, equivalent methods (as defined in §63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D5192,[a] or ASTM D7430,[a] or ASTM D6883,[a] or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for solid), or ASTM D4177[a] (for liquid), or ASTM D4057[a] (for liquid), or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B[a] (for solid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] (for biomass), or EPA 3050[a] (for solid fuel), or EPA 821-R-01-013[a] (for liquid or solid), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or ASTM D5864[a] for liquids and other solids, or ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173,[a] ASTM E871,[a] or ASTM D5864,[a] or ASTM D240, or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722[a] (for coal), EPA SW-846-7471B[a] or EPA 1631 or EPA 1631E (for solid samples), or EPA SW-846-7470A[a] (for liquid samples), or EPA 821-R-01-013 (for liquid or solid), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content	For fuel mixtures use Equation 8 in §63.7530.
2. HCl	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D5192,[a] or ASTM D7430,[a] or ASTM D6883,[a] or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for coal or biomass), ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B[a] (for solid samples), ASTM D2013/D2013M[a] (for coal), or ASTM D5198[a] (for biomass), or EPA 3050[a] or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), ASTM D5864, ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871,[a] or D5864,[a] or ASTM D240,[a] or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or equivalent.
	f. Measure chlorine concentration in fuel sample	EPA SW-846-9250,[a] ASTM D6721,[a] ASTM D4208[a] (for coal), or EPA SW-846-5050[a] or ASTM E776[a] (for solid fuel), or EPA SW-846-9056[a] or SW-846-9076[a] (for solids or liquids) or equivalent.

To conduct a fuel analysis for the following pollutant . . .	**You must . . .**	**Using . . .**
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content	For fuel mixtures use Equation 7 in §63.7530 and convert from chlorine to HCl by multiplying by 1.028.
3. Mercury Fuel Specification for other gas 1 fuels	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter, or	Method 30B (M30B) at 40 CFR part 60, appendix A-8 of this chapter or ASTM D5954,[a] ASTM D6350,[a] ISO 6978-1:2003(E),[a] or ISO 6978-2:2003(E),[a] or EPA-1631[a] or equivalent.
	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784[a] or equivalent.
4. TSM	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D5192,[a] or ASTM D7430,[a] or ASTM D6883,[a] or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for coal or biomass), or ASTM D4177,[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B[a] (for solid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] or TAPPI T266[a] (for biomass), or EPA 3050[a] or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or ASTM D5864[a] for liquids and other solids, or ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871,[a] or D5864, or ASTM D240,[a] or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	f. Measure TSM concentration in fuel sample	ASTM D3683,[a] or ASTM D4606,[a] or ASTM D6357[a] or EPA 200.8[a] or EPA SW-846-6020,[a] or EPA SW-846-6020A,[a] or EPA SW-846-6010C,[a] EPA 7060[a] or EPA 7060A[a] (for arsenic only), or EPA SW-846-7740[a] (for selenium only).
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content	For fuel mixtures use Equation 9 in §63.7530.

[a] Incorporated by reference, see §63.14.

[80 FR 72825, Nov. 20, 2015]

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limitsab

As stated in §63.7520, you must comply with the following requirements for establishing operating limits:

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits[ab]

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM, TSM, or mercury	a. Wet scrubber operating parameters	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to §63.7530(b)	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM, TSM, or mercury performance test	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests. (b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers)	i. Establish a site-specific minimum total secondary electric power input according to §63.7530(b)	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests. (b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	c. Opacity	i. Establish a site-specific maximum opacity level	(1) Data from the opacity monitoring system during the PM performance test	(a) You must collect opacity readings every 15 minutes during the entire period of the performance tests. (b) Determine the average hourly opacity reading for each performance test run by computing the hourly averages using all of the 15-minute readings taken during each performance test run. (c) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM (or TSM) emission limitation.

If you have an applicable emission limit for . . .	**And your operating limits are based on . . .**	**You must . . .**	**Using . . .**	**According to the following requirements**
2. HCl	a. Wet scrubber operating parameters	i. Establish site-specific minimum effluent pH and flow rate operating limits according to §63.7530(b)	(1) Data from the pH and liquid flow-rate monitors and the HCl performance test	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters	i. Establish a site-specific minimum sorbent injection rate operating limit according to §63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent	(1) Data from the sorbent injection rate monitors and HCl or mercury performance test	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction, as defined in §63.7575, to determine the required injection rate.
	c. Alternative Maximum SO_2 emission rate	i. Establish a site-specific maximum SO_2 emission rate operating limit according to §63.7530(b)	(1) Data from SO_2 CEMS and the HCl performance test	(a) You must collect the SO_2 emissions data according to §63.7525(m) during the most recent HCl performance tests. (b) The maximum SO_2 emission rate is equal to the highest hourly average SO_2 emission rate measured during the most recent HCl performance tests.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
3. Mercury	a. Activated carbon injection	i. Establish a site-specific minimum activated carbon injection rate operating limit according to §63.7530(b)	(1) Data from the activated carbon rate monitors and mercury performance test	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction, as defined in §63.7575, to determine the required injection rate.
4. Carbon monoxide for which compliance is demonstrated by a performance test	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to §63.7530(b)	(1) Data from the oxygen analyzer system specified in §63.7525(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test	a. Boiler or process heater operating load	i. Establish a unit specific limit for maximum operating load according to §63.7520(c)	(1) Data from the operating load monitors or from steam generation monitors	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test. (b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the highest hourly average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

[a] Operating limits must be confirmed or reestablished during performance tests.

[b]If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests. For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

[80 FR 72827, Nov. 20, 2015]

Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance

As stated in §63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to §63.7525(c) and §63.7535; and
	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining daily block average opacity to less than or equal to 10 percent or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation.
2. PM CPMS	a. Collecting the PM CPMS output data according to §63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to §63.7530(b)(4).
3. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to §63.7525 and operating the fabric filter such that the requirements in §63.7540(a)(7) are met.
4. Wet Scrubber Pressure Drop and Liquid Flow-rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to §63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to §63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in §63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§63.7525 and 63.7535; and
	b. Reducing the data to 30-day rolling averages; and

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
	c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to §63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and
	b. Reduce the data to 12-month rolling averages; and
	c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.
	d. Calculate the HCl, mercury, and/or TSM emission rate from the boiler or process heater in units of lb/MMBtu using Equation 15 and Equations 17, 18, and/or 19 in §63.7530.
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to §63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.7525(a)(7).
	b. Reducing the data to 30-day rolling averages; and
	c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test according to §63.7520(c).
11. SO_2 emissions using SO_2 CEMS	a. Collecting the SO_2 CEMS output data according to §63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average SO_2 CEMS emission rate to a level at or below the highest hourly SO_2 rate measured during the HCl performance test according to §63.7530.

[78 FR 7204, Jan. 31, 2013, as amended at 80 FR 72829, Nov. 20, 2015]

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 (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in §63.7550(b).

You must submit a(n)	The report must contain . . .	You must submit the report . . .
	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 for periods of startup and shutdown in Table 3 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) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard for periods of startup and shutdown, during the reporting period, the report must contain the information in §63.7550(d); and	
	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), or otherwise not operating, the report must contain the information in §63.7550(e)	

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013; 80 FR 72830, Nov. 20, 2015]

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	Applies to subpart DDDDD
§63.1	Applicability	Yes.
§63.2	Definitions	Yes. Additional terms defined in §63.7575
§63.3	Units and Abbreviations	Yes.
§63.4	Prohibited Activities and Circumvention	Yes.
§63.5	Preconstruction Review and Notification Requirements	Yes.
§63.6(a), (b)(1)-(b)(5), (b)(7), (c)	Compliance with Standards and Maintenance Requirements	Yes.
§63.6(e)(1)(i)	General duty to minimize emissions.	No. See §63.7500(a)(3) for the general duty requirement.
§63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.

Citation	**Subject**	**Applies to subpart DDDDD**
§63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.	No.
§63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§63.6(g)	Use of alternative standards	Yes, except §63.7555(d)(13) specifies the procedure for application and approval of an alternative timeframe with the PM controls requirement in the startup work practice (2).
§63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See §63.7500(a).
§63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	No. Subpart DDDDD specifies opacity as an operating limit not an emission standard.
§63.6(i)	Extension of compliance	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.
§63.6(j)	Presidential exemption.	Yes.
§63.7(a), (b), (c), and (d)	Performance Testing Requirements	Yes.
§63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at §63.7520(a) to (c).
§63.7(e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.
§63.8(c)(1)	Operation and maintenance of CMS	Yes.
§63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See §63.7500(a)(3).
§63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
§63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.
§63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program	Yes.

Citation	**Subject**	**Applies to subpart DDDDD**
§63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§63.8(e)	Performance evaluation of a CMS	Yes.
§63.8(f)	Use of an alternative monitoring method.	Yes.
§63.8(g)	Reduction of monitoring data	Yes.
§63.9	Notification Requirements	Yes.
§63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes.
§63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See §63.7555(d)(7) for recordkeeping of occurrence and duration and §63.7555(d)(8) for actions taken during malfunctions.
§63.10(b)(2)(iii)	Maintenance records	Yes.
§63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction	No.
§63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions	No. See §63.7555(d)(7) for recordkeeping of occurrence and duration and §63.7555(d)(8) for actions taken during malfunctions.
§63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
§63.10(d)(1) and (2)	General reporting requirements	Yes.
§63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See §63.7550(c)(11) for malfunction reporting requirements.

Citation	Subject	Applies to subpart DDDDD
§63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§63.11	Control Device Requirements	No.
§63.12	State Authority and Delegation	Yes.
§63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§63.1(a)(5),(a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9).	Reserved	No.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013; 80 FR 72830, Nov. 20, 2015]

Table 11 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis	a. Mercury	8.0E-07[a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis	a. Mercury	2.0E-06 lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
4. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
5. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
6. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
7. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
9. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05[a] lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
12. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	8.0E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
14. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
15. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07[a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
17. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
19. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run.
20. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provision of §63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see §63.14.

[c] An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[80 FR 72831, Nov. 20, 2015]

Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After May 20, 2011, and Before December 23, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	3.5E-06[a] lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO b. Filterable PM (or TSM)	460 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average 3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	1 hr minimum sampling time. Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05[a] lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO b. Filterable PM (or TSM)	910 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average 2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1 hr minimum sampling time. Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
	b. Mercury	4.8E-07[a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provision of §63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see §63.14.

[c]An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[80 FR 72834, Nov. 20, 2015]

Table 13 to Subpart DDDDD of Part 63— Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before April 1, 2013

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.6E-07[a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.8E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-02 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
6. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05[a] lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.*
9. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.6E-02 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
11. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average)	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
13. Units designed to burn liquid fuel	a. HCl	1.2E-03 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.9E-07[a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
14. Units designed to burn heavy liquid fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average)	1 hr minimum sampling time.
15. Units designed to burn light liquid fuel	a. CO (or CEMS)	130[a] ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 1-day block average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average)	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
17. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to §63.7515 if all of the other provision of

§63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see §63.14.

[c] An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[78 FR 7210, Jan. 31, 2013, as amended at 80 FR 72836, Nov. 20, 2015]

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a PSD/New Source Construction and Part 70 Operating Permit

Source Description and Location

Source Name:	**Riverview Energy Corporation**
Source Location:	**4702 E 2000 N, Dale, IN 47523**
County:	**Spencer**
SIC Code:	**2911 (Petroleum Refining), 2999 (Products of Petroleum and Coal, Not Elsewhere Classified)**
Operation Permit No.:	**T 147-39554-00065**
Permit Reviewer:	**Douglas Logan, P.E.**

Existing Approvals

There have been no previous approvals issued to this source.

County Attainment Status

The source will be located in Spencer County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective July 20, 2012, for the 2008 8-hour ozone standard.[1]
$PM_{2.5}$	Attainment effective October 27, 2011, for the annual $PM_{2.5}$ standard for Ohio Township. Unclassifiable or attainment effective April 5, 2005, for the annual $PM_{2.5}$ standard for the remainder of the county.
$PM_{2.5}$	Unclassifiable or attainment effective December 13, 2009, for the 24-hour $PM_{2.5}$ standard.
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
Pb	Unclassifiable or attainment effective December 31, 2011.
[1] Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005.	

(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides (NO_x) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NO_x emissions are considered when evaluating the rule applicability relating to ozone. Spencer County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NO_x emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
Spencer County has been classified as attainment for $PM_{2.5}$. Therefore, direct $PM_{2.5}$, SO_2, and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) Other Criteria Pollutants
Spencer County has been classified as attainment or unclassifiable in Indiana for all the other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

Since this source is classified as a fuel conversion plant, it is considered one (1) of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1), 326 IAC 2-3-2(g), or 326 IAC 2-7-1(22)(B). Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Greenhouse Gas (GHG) Emissions

On June 23, 2014, in the case of *Utility Air Regulatory Group v. EPA*, cause no. 12-1146, (available at http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA's guidance states that U.S. EPA will no longer require PSD or Title V permits for sources "previously classified as 'Major' based solely on greenhouse gas emissions."

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHG emissions to determine operating permit applicability or PSD applicability to a source or modification.

Description of New Source Construction

The Office of Air Quality (OAQ) has reviewed an application for a PSD/new source construction and Part 70 Operating Permit, submitted by Riverview Energy Corporation on January 25, 2018, relating to construction of a direct coal hydrogenation (DCH) facility to convert coal to liquid fuels. The following is a list of the proposed emission units and pollution control devices:

(a) Coal handling operations, identified as Block 1000, consisting of:

  (1) One (1) shelter-type railcar dump unloading facility, identified as EU-1000, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1000, exhausting to stack EU-1000, consisting of:

    (A) Two (2) enclosed receiving pits, identified as Receiving Pit 1 and Receiving Pit 2, discharging to Receiving Bin 1 and Receiving Bin 2, respectively.
    (B) Two (2) enclosed receiving bins, identified as Receiving Bin 1 and Receiving Bin 2, discharging to Drag Flight Feeder 1 and Drag Flight Feeder 2, respectively, with water spray dust suppression systems.
    (C) Two (2) enclosed drag flight feeders, identified as Drag Flight Feeder 1 and Drag Flight Feeder 2, discharging to the Unloading Conveyor, with water spray dust suppression systems.

  Under the NSPS, 40 CFR 60, Subpart Y, EU-1000 is an affected facility.

  (2) One (1) enclosed rail unloading conveyor discharging to Transfer Station 1, identified as Unloading Conveyor, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

  Under the NSPS, 40 CFR 60, Subpart Y, the Unloading Conveyor is an affected facility.

(3) One (1) enclosed transfer station discharging to Conveyor 1, Conveyor 2, or Conveyor 9, identified as Transfer Station 1 (EU-1001), approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

Under the NSPS, 40 CFR 60, Subpart Y, Transfer Station 1 (EU-1001) is an affected facility.

(4) One (1) enclosed feed conveyor discharging to Stacker 1 Boom Conveyor/Chute, identified as Conveyor 1, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 1 is an affected facility.

(5) One (1) enclosed stacker boom conveyor/chute discharging to Coal Stockpiles #1A & #1B, identified as Stacker 1 Boom Conveyor/Chute, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Stacker 1 Conveyor/Chute is an affected facility.

(6) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #1A and Stockpile #1B, with a maximum capacity of 93,000 tons, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Stockpiles #1A and #1B are affected facilities.

(7) One (1) enclosed feed conveyor discharging to Stacker 2 Boom Conveyor/Chute, identified as Conveyor 2, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 2 is an affected facility.

(8) One (1) enclosed stacker boom conveyor/chute discharging to Coal Stockpiles #2A & #2B, identified as Stacker 2 Boom Conveyor/Chute, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Stacker 2 Boom Conveyor/Chute is an affected facility.

(9) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #2A and Stockpile #2B, with a maximum capacity of 93,000 tons, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Stockpiles #2A and #2B are affected facilities.

(10) One (1) reclaimer for Stockpiles #1A & #1B, discharging to Reclaim Conveyor 6, identified as Reclaimer 1, approved in 2018 for construction, with a maximum capacity of

500 tons of coal per hour, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Reclaimer 1 is an affected facility.

(11) One (1) enclosed reclaimer conveyor, identified as Conveyor 6 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 6 is an affected facility.

(12) One (1) reclaimer for Stockpiles #2A & #2B, discharging to Reclaim Conveyor 7, identified as Reclaimer 2, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Reclaimer 2 is an affected facility.

(13) One (1) enclosed reclaimer conveyor, identified as Conveyor 7 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 7 is an affected facility.

(14) One (1) enclosed transfer station conveyor, identified as Conveyor 9 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 9 is an affected facility.

(15) One (1) enclosed reclaim transfer station discharging to Reclaim Conveyor 8, identified as Reclaim Transfer Station (EU-1006), approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Reclaim Transfer Station is an affected facility.

(16) One (1) enclosed conveyor, identified as Reclaim Conveyor 8 discharging to the Coal Mill and Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with particulate emissions controlled the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 8 is an affected facility.

(b) Coal drying loop, collectively identified as EU-1008, with emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008, consisting of the following:

(1) One (1) enclosed coal mill and pulverizer, identified as Coal Mill and Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer, with particulate emissions controlled the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Mill and Pulverizer is an affected facility.

(2) One (1) enclosed coal dryer, identified as Coal Dryer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer Baghouse, with particulate emissions controlled by the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer is an affected facility.

(3) One (1) natural gas and process fuel gas-fired heater, identified as Coal Dryer Heater EU-1007, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 55.8 MMBtu/hr (HHV), with emissions exhausting to Stack EU-1007.

Under the NSPS, 40 CFR 60, Subpart Ja, the Coal Dryer Heater (EU-1007) is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Heater (EU-1007) is part of an affected thermal dryer.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, the Coal Dryer Heater (EU-1007) is an affected source.

(4) One (1) process baghouse, identified as Coal Dryer Baghouse, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging fines to the Block 2000 Coal Hopper, exhausting particulate and filtered nitrogen to the condenser.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Baghouse is an affected facility.

(5) One (1) water-cooled condenser, identified as Drying Loop Condenser, approved in 2018 for construction, with a nominal capacity of 40 MMBtu/hr, with particulate emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008.

Under the NSPS, 40 CFR 60, Subpart Y, the Drying Loop Condenser is part of an affected thermal dryer.

(c) Additives handling operations, identified as Block 1500, consisting of:

(1) Three (3) pneumatic (nitrogen) truck unloading systems discharging to storage silos, approved in 2018 for construction, as follows:

(A) Coarse Additive Unloading, with a maximum capacity of 20.00 tons per hour.
(B) Fine Additive Unloading, with a maximum capacity of 20.00 tons per hour.
(C) Sodium Sulfide (Na_2S) Unloading, with a maximum capacity of 10.00 tons per hour.

(2) Three (3) nitrogen-blanketed storage silos, as follows:

(A) One (1) coarse additive silo, identified as T34, approved in 2018 for construction, controlled by baghouse EU-1501, exhausting to stack EU-1501.
(B) One (1) fine additive silo, identified as T33, approved in 2018 for construction, controlled by baghouse EU-1502, exhausting to stack EU-1502.
(C) One (1) Na_2S silo, identified as T35, approved in 2018 for construction, controlled by baghouse EU-1503, exhausting to stack EU-1503.

(3) One (1) nitrogen-blanketed fine additive production system, identified as Fine Additive Production System, approved in 2018 for construction, with a maximum capacity of 3.28 tons per hour, controlled by baghouse EU-1504, exhausting to stack EU-1504, consisting of:

(A) One (1) coarse additive silo rotary feeder solid weigh scale.
(B) One (1) coarse additive screw conveyor discharging to the Fine Additive Production System.
(C) One (1) additive size reduction system, identified as Fine Additive Production System discharging to the T33 or the Block 2000 coarse additive transfer system.

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(1) One (1) enclosed hopper receiving coal from Block 1000 Coal Dryer Baghouse and discharging to the Feed Prep Screw Conveyor, identified as Coal Hopper, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Hopper is an affected facility.

(2) One (1) enclosed screw conveyor, identified as Closed Screw Conveyor, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Feed Premix Drum, identified as Closed Screw Conveyor, with particulate emissions controlled by the Coal Handling System Filter, exhausting to stack EU-2005.

Under the NSPS, 40 CFR 60, Subpart Y, the Closed Screw Conveyor is an affected facility.

(3) One (1) nitrogen-blanketed coarse additive transfer system, identified as Coarse Additive Screw Conveyor, approved in 2018 for construction, with a maximum capacity of 2.20 tons per hour, receiving material from the Block 1500 coarse additive silo and discharging to the Feed Premix Drum, with particulate emissions controlled by the Coarse Additive System Filter, exhausting to stack EU-2006.

(4) One (1) nitrogen-blanketed fine additive transfer system, identified as Fine Additive Handling System, approved in 2018 for construction, with a maximum capacity of 3.28 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Fine Additive System Filter, exhausting to stack EU-2007, consisting of:

(A) One (1) fine additive silo rotary feeder solid weigh scale.
(B) One (1) fine additive screw conveyor discharging to the Block 2000 feed premix drum.

(5) One (1) nitrogen-blanketed Na_2S slurry preparation system, identified as Na_2S Slurry Preparation, approved in 2018 for construction, with a maximum capacity of 0.077 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Na_2S Handling System Filter, exhausting to stack EU-2008, consisting of:

(A) One (1) Na_2S silo rotary feeder solid weigh scale.
(B) One (1) Na_2S screw conveyor discharging to the Na_2S mixing drum.
(C) One (1) nitrogen-blanketed mixing drum for Na_2S and Block 2000 vacuum tower VGO (vacuum gas oil) discharging to the feed premix drum.

Under the NSPS, 40 CFR 60, Subpart GGGa, the mixing drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the mixing drum is an affected source.

(6) One (1) feed premix drum, identified as Feed Premix Drum, approved in 2018 for construction, receiving coal, solid additives, and recycled vacuum gas oil (VGO) and

discharging to the feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed premix drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed premix drum is an affected source.

(7) One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2018 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

Under the NSPS, 40 CFR 60, Subpart Ja, the feed heater EU-2001 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed heater EU-2001 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed heater EU-2001 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, feed heater EU-2001 is an affected source.

(8) One (1) natural gas and process fuel gas-fired indirect treat gas heater, identified as EU-2002, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 52.8 MMBtu/hr (HHV), receiving hydrogen from Block 7000 and discharging to the 1st stage reactors, exhausting to stack EU-2002.

Under the NSPS, 40 CFR 60, Subpart Ja, the treat gas heater EU-2002 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, treat gas heater EU-2002 is an affected source.

(9) One (1) first stage reactor - liquid phase hydrocracking system, identified as LPH, approved in 2018 for construction, discharging to the hot separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the first stage reactor - liquid phase hydrocracking system is an affected source.

(10) One (1) hot separator, identified as Hot Separator, approved in 2018 for construction, discharging vapor to the 2nd stage reactors and liquids to the vacuum column feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the hot separator is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the hot separator is an affected source.

(11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2018 for construction, equipped with Low-NO_X

burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the vacuum distillation tower, exhausting to stack EU-2003.

Under the NSPS, 40 CFR 60, Subpart Ja, the vacuum column feed heater EU-2003 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum column feed heater EU-2003 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum column feed heater EU-2003 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, vacuum column feed heater EU-2003 is an affected source.

(12) One (1) vacuum distillation tower, identified as Vacuum Distillation Column, approved in 2018 for construction, discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 4000, phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum distillation tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the vacuum distillation tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum distillation tower is an affected source.

(13) One (1) second stage reactor - gas phase hydrotreating system, identified as GPH, approved in 2018 for construction, discharging to the cold separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the second stage reactor - gas phase hydrotreating system is an affected source.

(14) One (1) cold separator , identified as Cold Separator, approved in 2018 for construction, discharging non-phenolic sour water to Block 3000 and hydrocarbons to the fractionator heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the cold separator is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the cold separator is an affected source.

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

Under the NSPS, 40 CFR 60, Subpart Db, fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, the fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator heater is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator heater is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, fractionator heater EU-2004 is an affected source.

(16) One (1) fractionator tower, identified as Fractionator Tower, approved in 2018 for construction, discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix Drum, and non-phenolic sour water to Block 3000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the fractionator tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator tower is an affected source.

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

(A) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the HP Absorber and LP Absorber are affected sources.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the HP Absorber and LP Absorber is an affected source.

(e) Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

(A) One (1) heat exchanger, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) stripper column , identified as Stripper, approved in 2018 for construction, discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger and the reboiler and vapor to the overheads condenser, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(C) One (1) water-cooled condenser, identified as Overheads Condenser, approved in 2018 for construction, discharging condensate to the stripper condenser accumulator, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(D) One (1) accumulator drum, identified as Stripper Condenser Accumulator, approved in 2018 for construction, discharging condensate to stripper reflux and the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(E) One (1) steam-heated reboiler, identified as Stripper Reboiler, approved in 2018 for construction, discharging lean amine to the stripper reflux, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Amine Recovery Unit is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Amine Recovery Unit part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Amine Recovery Unit is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Amine Recovery Unit is an affected source.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Sour Water Stripping System is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Sour Water Stripping System is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Sour Water Stripping System is an affected source.

(3) Sulfur Recovery System, consisting of:

(A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the TGTU A Heat Exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
(xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605A Incinerator and A-605A Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit A is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit A is an affected source.

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
(xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605B Incinerator and A-605B Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit B is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit B is an affected source.

(f) Offsites operations, identified as Block 4000, consisting of:

(1) Flares, as follows:

(A) One (1) natural gas and process fuel gas-fired flare identified as High Pressure (HP) Flare, approved in 2018 for construction, servicing overpressure and emergency reliefs from Block 2000 VEBA Combi Cracker operations, controlling emissions from Block 2000 depressurization system, with pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(B) One (1) natural gas and process fuel gas-fired flare, identified as Low Pressure (LP) Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 7000 Hydrogen Unit operations, controlling emissions Block 7000 start-up and shut-down vents, and a continuous sweep stream from the Block 2000 slop tank, with a sweep and pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(C) One (1) natural gas and process fuel gas-fired flare, identified as Sulfur Block Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 3000 Sulfur Recovery operations and sulfur loading, controlling emergency streams from Sulfur Recovery Units A and B, and a continuous sweep stream from the sour water storage tanks, with a sweep and pilot heat input capacity of 0.77 MMBtu/hr (LHV), exhausting to the atmosphere.

(D) One (1) natural gas and process fuel gas-fired flare, identified as Loading Flare, approved in 2018 for construction, servicing Block 4000 naphtha, diesel, and ammonia loading operations, with a pilot heat input capacity of 0.20 MMBtu/hr (LHV), exhausting to the atmosphere.

Under the NSPS, 40 CFR 60, Subpart Ja, the flares are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, the flares are affected facilities.

Under the NESHAP, 40 CFR 63, Subpart CC, the flares are affected sources.

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T1	IFR	Naphtha product	4,629,879 (17,524)	-
T2	IFR	Naphtha product	4,629,879 (17,524)	-
T3	FR	Diesel product	4,525,796 (17,130)	-
T4	FR	Diesel product	4,525,796 (17,130)	-
T5	FR	Diesel product	4,525,796 (17,130)	-
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)	-
T7	FR	Molten sulfur	342,367 (1,296)	-

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T8	FR	Molten sulfur	342,367 (1,296)	-
T9	HPV	Ammonia product	36,720 (17,524)	-
T10	FR	Residue surge tank 1	926,980 (17,524)	-
T11	FR	Residue surge tank 2	926,980 (3,509)	-
T12	FR	Residue feed tank	926,980 (3,509)	-
T13	FR	VGO tank 1	926,980 (3,509)	-
T14	FR	VGO tank 2	926,980 (3,509)	-
T15	HPV	LPG storage	48,872 (185)	-
T16	FR	Slop tank	4,195,581 (15,880)	LP flare
T17	FR	Diesel fuel tank	23,775 (90)	-
T18	FR	Non-phenolic sour water storage tank 1	1,268,026 (4,799)	SB flare
T19	FR	Non-phenolic sour water storage tank 2	1,268,026 (4,799)	SB flare
T20	FR	Non-phenolic sour water storage tank 3	1,268,026 (4,799)	SB flare
T21	FR	Phenolic sour water storage tank	40,947 (155)	SB flare
T22	FR	Stripped non-phenolic sour water surge tank	1,268,026 (4,799)	-
T23	FR	Stripped phenolic sour water surge tank	13,737 (52)	-
T24	FR	Amine surge/deinventory tank	63,943 (242)	-
T25	FR	Fresh amine tank	63,943 (242)	-
T26	FR	Amine containment tank (sump)	793 (3)	-

1. *FR - fixed roof, IFR - internal floating roof, HPV-horizontal pressure vessel*
2. *Tank vents to flares are part of sweep and pilot gas streams.*

Under the NSPS, 40 CFR 60, Subpart Kb, T1, T2, and T6 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, T1 - T6 and T10 - T15 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart QQQ, T16 is part of an affected facility.

Under the NSPS, 40 CFR 61, Subpart FF, T16 and T18 - T21 are part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, T1 - T6, T10 - T14, T16, and T18-T23 are part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart WW, T3 - T6 and T10 - T14 are affected sources.

(3) Loading operations, as follows:

(A) One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Product Loading Rack is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart BB, the Product Loading Rack is an affected source.

Under the NESHAP, 40 CFR 63, Subpart CC, the Product Loading Rack is an affected source.

(B) One (1) single-spot railcar loading rack for ammonia, identified as Ammonia Loading Rack, approved in 2018 for construction, with a bottlenecked capacity of 15,024,167 gallons per year, controlled by the Loading Flare.

(C) One (1) single-spot railcar loading rack for molten sulfur, identified as Sulfur Loading Rack, approved in 2018 for construction, with a bottlenecked capacity of 63,781 tons per year, controlled by the Sulfur Block Flare.

(g) Residue solidification operations, identified as Block 5000, as follows:

(1) Four (4) pastillators, identified as EU-5001A - EU5001D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5001.

(2) Four (4) pastillators, identified as EU-5002A - EU5002D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5002.

(3) Four (4) pastillators, identified as EU-5003A - EU5003D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5003.

(4) Four (4) pastillators, identified as EU-5004A - EU5004D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5004.

(5) Enclosed conveyors for residue pellets, with particulate emissions controlled by filters EU-5009, EU-5010, and EU-5011, as follows:

(A) One (1) enclosed conveyor, identified as Block 1 & 2 transfer conveyors, with a maximum capacity of 34.33 tons per hour, receiving pastillators from the eight (8) pastillators, identified as EU-5001A - EU5001D and EU-5002A - EU5002D.

(B) One (1) enclosed conveyor, identified as Block 3 & 4 transfer conveyors, with a maximum capacity of 34.33 tons per hour, receiving pastillators from the eight (8) pastillators, identified as EU-5003A - EU5003D and EU-5004A - EU5004D.

(C) One (1) enclosed loading conveyor, identified as Loading Conveyor, approved in 2018 for construction, with a maximum capacity of 51.49 tons per hour, receiving pastillators from Block 1 & 2 and Block 3 & 4 transfer conveyors, and discharging to the bulk container loading station, railcar residue silo, or swing residue silo.

(6) One (1) residue bulk container loading station, identified as EU-5009, approved in 2018 for construction, with a maximum capacity of 8.00 tons per hour, using filter EU-5009 for particulate control and exhausting to stack EU-5009.

(7) One (1) railcar residue storage silo, identified as EU-5010, approved in 2018 for construction, with a maximum capacity of 1,236 tons per day, using baghouse EU-5010 for particulate control and exhausting to stack EU-5010.

(8) Two (2) residue loading hoppers, identified as EU-5005 and EU-5006, approved in 2018 for construction, with a combined maximum capacity of 1,236 tons per day, receiving residue from the railcar residue storage silo, using baghouse EU-5010 for particulate control and exhausting to stack EU-5010.

(9) One (1) swing residue storage silo, identified as EU-5011, approved in 2018 for construction, with a maximum capacity of 1,236 tons per day, using baghouse EU-5011 for particulate control and exhausting to stack EU-5011.

(10) Two (2) residue loading hoppers, identified as EU-5007 and EU-5008, approved in 2018 for construction, with a combined maximum capacity of 1,236 tons per day, receiving residue from the swing residue storage silo, using baghouse EU-5011 for particulate control and exhausting to stack EU-5011.

(11) Residue loadout operations using spouts and choke flow-practices, as follows:

(A) Two (2) railcar loadspots, approved in 2018 for construction.

(B) Two (2) swing loadspots, approved in 2018 for construction, accommodating either trucks or railcars.

(h) Utilities operations, identified as Block 6000, consisting of:

(1) One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 68.50 MMBtu/hr (HHV), exhausting to stack EU-6000.

Under the NSPS, 40 CFR 60, Subpart Dc, boiler EU-6000 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, boiler EU-6000 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, boiler EU-6000 is an affected source.

(2) One (1) three-cell crossflow mechanical draft cooling tower, identified as EU-6001, approved in 2018 for construction, with a maximum capacity of 32,000 gallons per hour, equipped with mist eliminators and exhausting to stacks EU-6001, EU-6002, and EU-6003.

(3) One (1) diesel engine-driven emergency generator, identified as EU-6006, approved in 2018 for construction, with a maximum heat input capacity of 19.60 MMBtu/hr (2,800 hp) (average heating value), exhausting to stack EU-6006.

Under the NSPS, 40 CFR 60, Subpart IIII, emergency generator EU-6006 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart ZZZZ, emergency generator EU-6006 is an affected source.

(4) One (1) diesel engine-driven emergency fire pump, identified as EU-6008, approved in 2018 for construction, with a maximum heat input capacity of 5.25 MMBtu/hr (750 hp) (average heating value), exhausting to stack EU-6008.

Under the NSPS, 40 CFR 60, Subpart IIII, emergency fire pump EU-6008 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart ZZZZ, emergency fire pump EU-6008 is an affected source.

(i) Water supply and treatment operations, identified as Block 6500, consisting of:

(1) One (1) pneumatic lime truck unloading system, identified as Lime Unloading, approved in 2018 for construction, with a maximum capacity of 20.00 tons per hour, discharging to silo EU-6501.

(2) One (1) lime storage silo, identified as EU-6501, approved in 2018 for construction, with a maximum capacity of 20.00 tons per hour, with particulate emissions controlled by dust collector EU-6501 and exhausting to stack EU-6501.

(j) Hydrogen unit operations, identified as Block 7000, as follows:

(1) Hydrogen Plant 1, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7003, identified as Feed Water Treatment System 1, approved in 2018 for construction, exhausting to stack EU-7003.

(B) One (1) feed preparation train, identified as Feed Prep 1, approved in 2018 for construction, consisting of:

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7001, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7001, is an affected facility.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 1, approved in 2018 for construction, discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 1, approved in 2018 for construction, discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 1 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 1 is an affected source.

(2) Hydrogen Plant 2, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7004, identified as Feed Water Treatment System 2, approved in 2018 for construction, exhausting to stack EU-7004.

(B) One (1) feed preparation train, identified as Feed Prep 2, approved in 2018 for construction, consisting of:

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7002, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7002, is an affected facility.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 2, approved in 2018 for construction, discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 2, approved in 2018 for construction, discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 2 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 2 is an affected source.

(k) Wastewater treatment operations, identified as Block 8000, as follows:

(1) One (1) wastewater junction box with associated process drains, identified as Oily Water Sump, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8002.

(2) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Water Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and water to MH1.

(3) One (1) wastewater junction box with, identified as MH1, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8003.

(4) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Amine Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and amine solution to the Rich Amine Return Header.

(5) One (1) biological wastewater treatment system, approved in 2018 for construction, with emissions exhausting to vent EU-8001.

Under the NSPS, 40 CFR 60, Subpart QQQ, the process drains, junction boxes, Oily Water Separator, Oily Amine Separator, associated sewer lines, and any secondary oil-water separator in the biological wastewater treatment system are an affected aggregate facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Oily Water Separator, Oily Amine Separator, and any secondary oil-water separator in the biological wastewater treatment system are affected sources.

Under the NESHAP, 40 CFR 63, Subpart CC, the wastewater streams and treatment operations associated with petroleum refining process units are part of a new affected source..

Insignificant Activities

The source also consists of the following insignificant activities, as defined at 326 IAC 2-7-1(21):

(a) The following VOC and HAP storage containers:

  (1) Storage tanks with capacity less than or equal to one thousand (1,000) gallons and annual throughputs equal to or less than twelve thousand (12,000) gallons.

  (2) Vessels storing the following:

    (A) Hydraulic oils.
    (B) Lubricating oils.

(b) Production related activities, including the following:

  (1) Cleaners and solvents characterized as having a vapor pressure equal to or less than:

    (A) two (2.0) kilo Pascals (fifteen (15) millimeters of mercury or three-tenths (0.3) pound per square inch) measured at thirty-eight (38) degrees Centigrade (one hundred (100) degrees Fahrenheit); or
    (B) seven-tenths (0.7) kilo Pascal (five (5) millimeters of mercury or one-tenth (0.1) pound per square inch) measured at twenty (20) degrees Centigrade (sixty-eight (68) degrees Fahrenheit); the use of which, for all cleaners and solvents combined, does not exceed one hundred forty-five (145) gallons per twelve (12) months.

  (2) Closed loop heating and cooling systems.

(c) Repair activities, including the following:

  (1) Replacement or repair of electrostatic precipitators, bags in baghouses, and filters in other air filtration equipment.
  (2) Heat exchanger cleaning and repair.
  (3) Process vessel degassing and cleaning to prepare for internal repairs.

(d) Paved roads and parking lots with public access.

(e) Conveyors as follows:

(1) Underground conveyors.

(f) Routine maintenance and repair of buildings, structures, or vehicles at the source where air emissions from those activities would not be associated with any production process, including the following:

(1) Purging of gas lines.
(2) Purging of vessels.

(g) Flue gas conditioning systems and associated chemicals, such as the following:

(1) Ammonia.

(h) Equipment used to collect any material that might be released during a malfunction, process upset, or spill cleanup, including the following:

(1) Tanks.
(2) Fluid handling equipment.

(i) Blowdown for the following:

(1) Boiler.
(2) Cooling tower.

(j) Activities associated with emergencies as follows:

(1) On-site fire training approved by IDEM.

(k) Purge double block and bleed valves.

(l) An emission unit or activity whose potential uncontrolled emissions meet the exemption levels specified in 326 IAC 2-1.1-3(e)(1) or the exemption levels specified in the following, whichever is lower:

- For lead or lead compounds measured as elemental lead, the exemption level is six-tenths (0.6) ton per year or three and twenty-nine hundredths (3.29) pounds per day.
- For carbon monoxide (CO), the exemption limit is twenty-five (25) pounds per day.
- For sulfur dioxide, the exemption level is five (5) pounds per hour or twenty-five (25) pounds per day.
- For VOC, the exemption limit is three (3) pounds per hour or fifteen (15) pounds per day.
- For nitrogen oxides (NOx), the exemption limit is five (5) pounds per hour or twenty-five (25) pounds per day.
- For PM10 or direct PM2.5, the exemption level is either five (5) pounds per hour or twenty-five (25) pounds per day.

As follows:

(1) Fugitive leaks of VOC and HAPs from equipment in VOC service, subject to NSPS or NESHAP, but individually less than the exemption levels listed above.

(2) One (1) emergency generator fuel tank, identified as EU-6005, approved in 2018 for construction, with a nominal capacity of 2,000 gallons and an expected annual throughput of 69,450 gallons, using no controls and exhausting to stack EU-6005.

(3) One (1) emergency fire pump fuel tank, identified as EU-6007, approved in 2018 for construction, with a nominal capacity of 500 gallons and an expected annual throughput of 19,950 gallons, using no controls and exhausting to stack EU-6007.

Trivial Activities

The source also consists of the following trivial activities, as defined at 326 IAC 2-7-1(42):

(a) Water related activities, including the following:

- (1) Water treatment activities used to provide potable and process water for the plant, excluding any activities associated with wastewater treatment.
- (2) Steam traps, vents, leaks, and safety relief valves.
- (3) Cooling ponds.
- (4) Demineralized water tanks and demineralizer vents.
- (5) Boiler water treatment operations, not including cooling towers.
- (6) Oxygen scavenging (deaeration) of water.
- (7) Pressure washing of equipment.

(b) Combustion activities, including the following:

- (1) Combustion emissions from propulsion of mobile sources.
- (2) Fuel use related to food preparation for on-site consumption.
- (3) Tobacco smoking rooms and areas.
- (4) Indoor and outdoor kerosene heaters.

(c) Activities related to ventilation, venting equipment, and refrigeration, including the following:

- (1) Ventilation exhaust, central chiller water systems, refrigeration, and air conditioning equipment, not related to any industrial or production process, including natural draft hoods or ventilating systems that do not remove air pollutants.
- (2) Stack and vents from plumbing traps used to prevent the discharge of sewer gases, handling domestic sewage only, excluding those at wastewater treatment plants or those handling any industrial waste.
- (3) Vents from continuous emissions monitors and other analyzers.
- (4) Natural gas pressure regulator vents, excluding venting at oil and gas production facilities.
- (5) Air vents from air compressors.
- (6) Vents for air cooling of electric motors provided the air does not commingle with regulated air pollutants.

(d) Activities related to routine fabrication, maintenance, and repair of buildings, structures, equipment, or vehicles at the source where air emissions from those activities would not be associated with any commercial production process, including the following:

- (1) Activities associated with the repair and maintenance of paved and unpaved roads, including paving or sealing, or both, of parking lots and roadways.
- (2) Painting, including interior and exterior painting of buildings, and solvent use excluding degreasing operations utilizing halogenated organic solvents.
- (3) Brazing, soldering, or welding operations and associated equipment.
- (4) Batteries and battery charging stations except at battery manufacturing plants.
- (5) Lubrication, including the following:
  - (A) Hand-held spray can lubrication.
  - (B) Dipping metal parts into lubricating oil.
  - (C) Manual or automated addition of cutting oil in machining operations.
- (6) Nonasbestos insulation installation or removal.
- (7) Tarring, retarring, and repair of building roofs.
- (8) Instrument air dryer and filter maintenance.
- (9) Manual tank gauging.

(e) Activities performed using hand-held equipment, including the following:

- (1) Application of hot melt adhesives with no VOC in the adhesive formulation.
- (2) Cutting, excluding cutting torches.
- (3) Drilling.
- (4) Grinding.
- (5) Machining wood, metal, or plastic.
- (6) Polishing.
- (7) Routing.
- (8) Sanding.
- (9) Sawing.
- (10) Surface grinding.
- (11) Turning wood, metal, or plastic.

(f) Housekeeping and janitorial activities and supplies, including the following:

- (1) Vacuum cleaning systems used exclusively for housekeeping or custodial activities, or both.
- (2) Restrooms and associated cleanup operations and supplies.
- (3) Alkaline or phosphate cleaners and associated equipment.
- (4) Mobile floor sweepers and floor scrubbers.

(g) Office related activities, including the following:

- (1) Office supplies and equipment.
- (2) Photocopying equipment and associated supplies.
- (3) Paper shredding.

(h) Storage equipment and activities, including the following:

- (1) Pressurized storage tanks and associated piping for the following:

    - (A) Anhydrous ammonia.
    - (B) Liquid petroleum gas (LPG).
    - (C) Natural gas.

- (2) Storage tanks, vessels, and containers holding or storing liquid substances that do not contain any VOC or HAP.
- (3) Storage of drums containing maintenance raw materials.
- (4) Storage of the following:

    - (A) Any non-HAP containing material in solid form stored in a sealed or covered container.

- (5) Portable containers used for the collection, storage, or disposal of materials provided the container capacity is equal to or less than forty-six hundredths (0.46) cubic meters and the container is closed, except when the material is added or removed.

(i) Emergency and standby equipment, including the following:

- (1) Process safety relief devices installed solely for the purpose of minimizing injury to persons or damage to equipment that could result from abnormal process operating conditions, including the following:

    - (A) Explosion relief vents, diaphragms, or panels.
    - (B) Rupture discs.
    - (C) Safety relief valves.

(j) Sampling and testing equipment and activities, including the following:

- (1) Equipment used for quality control/assurance or inspection purposes, including sampling equipment used to withdraw materials for analysis.
- (2) Sampling activities, including the following:
  - (A) Sampling of waste.
  - (B) Glove box sampling, charging, and packaging.
- (3) Instrument air dryers and distribution.

(k) Activities generating limited amounts of fugitive dust, including the following:

- (1) Road salting and sanding.

(l) Activities associated with production, including the following:

- (1) Electrical resistance welding.
- (2) Application equipment for hot melt adhesives with no VOC in the adhesive formulation.
- (3) Air compressors and pneumatically operated equipment, including hand tools.
- (4) Compressor or pump lubrication and seal oil systems.

(m) Miscellaneous equipment, but not emissions associated with the process for which the equipment is used, and activities, including the following:

- (1) Equipment used for surface coating, painting, dipping, or spraying operation, except those that will emit VOCs or HAPs.
- (2) Manual loading and unloading operations.
- (3) Construction and demolition operations.

Enforcement Issues

There are no pending enforcement actions.

Stack Summary

Stack ID	Operation	Height (ft)	Diameter (ft)	Flow Rate (acfm)	Temperature (°F)
EU-1000	EU-1000	50	1.67	7,172	ambient
EU-1001	EU-1001	175	2.00	10,094	ambient
EU-1006	EU-1006	50	1.83	6,166	ambient
EU-1007	EU-1007	150	3.00	21,271	525
EU-1008	EU-1008	50	3.28	15,310	136
EU-1501	EU-1501	121	.83	945	ambient
EU-1502	EU-1502	121	.83	945	ambient
EU-1503	EU-1503	79	.67	768	ambient
EU-1504	EU-1504	49	0.33	260	ambient
EU-2001	EU-2001	200	5.25	48,865	525
EU-2002	EU-2002	200	3.15	17,484	405
EU-2003	EU-2003	200	1.57	4,671	800
EU-2004	EU-2004	200	5.48	52,678	420
EU-2005	EU-2005	121	0.33	201	ambient
EU-2006	EU-2006	121	0.33	242	ambient
EU-2007	EU-2007	121	0.33	260	ambient

Stack ID	Operation	Height (ft)	Diameter (ft)	Flow Rate (acfm)	Temperature (°F)
EU-2008	EU-2008	121	0.17	48	ambient
EU-3001	EU-3001	200	3.67	25,169	529
EU-3002	EU-3002	200	3.67	25,169	529
EU-4001	EU-4001	150	0.33	333	1831
EU-4004	EU-4004	150	0.33	333	1831
EU-4005	EU-4005	150	1.31	5,325	1831
EU-4006	EU-4006	150	1.31	5,325	1831
EU-5001	EU-5001A/B/C/D	50	2.00	8,000	500
EU-5002	EU-5002A/B/C/D	50	2.00	8,000	500
EU-5003	EU-5003A/B/C/D	50	2.00	8,000	500
EU-5004	EU-5004A/B/C/D	50	2.00	8,000	500
EU-5009	EU-5009	49	0.25	101	ambient
EU-5010	EU-5010	131	0.33	161	ambient
EU-5011	EU-5011	131	0.33	161	ambient
EU-6000	EU-6000	100	3.51	22,159	400
EU-6001	EU-6001	76	21.00	583,486	91
EU-6002	EU-6002	76	21.00	583,486	91
EU-6003	EU-6003	76	21.00	583,486	91
EU-6006	EU-6006	15	1.33	15,197	770
EU-6008	EU-6008	15	1.33	15,197	770
EU-6501	EU-6501	121	0.67	555	ambient
EU-7001	EU-7001	164	11.32	229,374	319
EU-7002	EU-7002	164	11.32	229,374	319
EU-7003	EU-7003	80	1.67	1,887	224
EU-7004	EU-7004	80	1.67	1,887	224
EU-8001	EU-8001	75	1.00	1611	100
EU-8002	EU-8002	6.25	0.17	11.2	100
EU-8003	EU-8003	6.25	0.17	4.5	100

Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

Permit Level Determination – Part 70 New Source Construction

Pursuant to 326 IAC 2-7-1(30), Potential to Emit is defined as “the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U.S. EPA.”

The following table is used to determine the appropriate permit level under 326 IAC 2-7. This table reflects the PTE before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit. If the control equipment has been determined to be integral, the table reflects the PTE after consideration of the integral control device.

	Part 70: Uncontrolled PTE (tons/year)								
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NO_X**	**VOC**	**CO**	**Single HAP***	**Combined HAPs**
Total for Source	**30,697**	**4,906**	**1,847**	**208**	**614**	**695**	**502**	**32.64**	**116.87**
Part 70 Threshold	NA	100	100	100	100	100	100	10	25

*Single highest source-wide HAP, n-hexane.

(a) The potential to emit (as defined in 326 IAC 2-7-1(30)) of PM_{10}, $PM_{2.5}$, SO_2, NOx, VOC, and CO is each equal to or greater than one hundred (100) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit.

(b) The potential to emit (as defined in 326 IAC 2-7-1(30)) of any single HAP is equal to or greater than ten (10) tons per year and the potential to emit (as defined in 326 IAC 2-7-1(30)) of a combination of HAPs is equal to or greater than twenty-five (25) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit.

Prevention of Significant Deterioration (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 New Source Review Permit, and only to the extent that the effect of the control equipment is made practically enforceable in the permit. If the control equipment has been determined to be integral, the table reflects the PTE after consideration of the integral control device.

	Source-Wide Emissions after Issuance (ton/year)									
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$[1]**	**SO_2**	**NO_X**	**VOC**	**CO**	**CO_2e**	**Sulfuric Acid Mist[2]**	**H_2S**	**TRS**
Coal Handling, Block 1000	2.85	2.85	2.85	-	-	-	-	-	-	-	-
Coal drying heater, EU-1007	0.46	1.83	1.83	0.44	7.33	1.32	8.92	29,127	-	-	-
Additive handling, Block 1500	0.23	0.23	0.23	-	-	-	-	-	-	-	-
Soilds handling, Block 2000	0.05	0.05	0.05	-	-	-	-	-	-	-	-
Feed heater, EU-2001	1.07	4.22	4.22	1.01	16.87	3.04	20.53	67,023	-	-	-
Treat gas heater, EU-2002	0.44	1.73	1.73	0.39	6.94	1.25	8.44	27,561	-	-	-
Vacuum column feed heater, EU-2003	0.07	0.30	0.30	0.09	1.18	0.21	1.44	4,698	-	-	-
Fractionator heater, EU-2004	1.30	5.12	5.12	1.18	20.50	3.69	24.94	81,430	-	-	-
Sulfur Recovery, Block 3000	0.61	2.44	2.44	144.39	33.00	1.78	27.06	40,872	8.05	2.93	4.13
HP, LP, SB flares	0.13	0.50	0.50	66.66	11.99	31.61	40.97	15,908	-	-	-
Loading rack flare, EU-4001	0.002	0.01	0.01	0.001	0.29	0.01	0.98	559	-	-	-
Product loading rack	-	-	-	-	-	2.88	-	-	-	-	-

	Source-Wide Emissions after Issuance (ton/year)										
Process / Emission Unit	**PM**	**PM$_{10}$**	**PM$_{2.5}$**[1]	**SO$_2$**	**NO$_X$**	**VOC**	**CO**	**CO$_2$e**	**Sulfuric Acid Mist**[2]	**H$_2$S**	**TRS**
Block 4000 storage tanks	-	-	-	-	-	12.67	-	-	-	-	-
Residue solidification, Block 5000	0.03	0.03	0.03	-	-	18.37	-	-	-	-	-
Boiler, EU-6000	0.57	2.25	2.25	0.53	9.00	1.62	10.95	35,756	-	-	-
Cooling tower, EU-6001, EU-6002, & EU-6003	0.84	0.48	0.002	-	-	5.89	-	-	-	-	-
Fuel tanks, EU-6005, EU-6007)	-	-	-	-	-	0.001	-	-	-	-	-
Emergency engines, EU-6006 & EU-6008	0.07	0.07	0.07	0.003	1.97	1.97	1.24	249	-	-	-
Lime storage silo, EU-6501	0.04	0.04	0.04	-	-	-	-	-	-	-	-
Hydrogen plant, Block 7000	44.08	44.08	35.26	10.40	47.75	39.05	156.21	1,974,702	-	-	-
Wastewater treatment, Block 8000	-	-	-	-	-	1.65	-	-	-	-	-
Total	52.85	66.23	56.94	224.37	156.83	127.00	301.67	2,277,884	8.05	2.93	4.13
Fugitive Emissions											
Equipment leaks	-	-	-	-	-	176.22	-	-	-	-	-
Paved roads	11.69	2.34	0.57	-	-	-	-	-	-	-	-
Total for Source	**64.54**	**68.57**	**57.51**	**224.37**	**156.83**	**303.22**	**301.67**	**2,277,884**	**8.05**	**2.93**	**4.13**
PSD Major Source Thresholds	100	100	100	100	100	100	100	100,000	100	100	100

Notes:

1. PM$_{2.5}$ listed is direct PM$_{2.5}$.

(a) This new stationary source is major for PSD (326 IAC 2-2) because the pollutants SO$_2$, NOx, VOC, and CO, each have emissions equal to or greater than the PSD major source threshold. Therefore, pursuant to 326 IAC 2-2, the PSD requirements apply.

Federal Rule Applicability Determination

Federal rule applicability for this new source has been reviewed as follows:

New Source Performance Standards (NSPS):

(a) The requirements of the Emissions Guidelines and Compliance Times for Sulfuric Acid Production Units, 40 CFR 60, Subpart Cd and 326 IAC 12, are not included in the permit for the sulfur recovery units, because the units are not existing sulfuric acid production units as defined at 40 CFR 60.81(a). As defined at 40 CFR 60.81(a), *Sulfuric acid production unit* means any facility producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides and mercaptans, or acid sludge, but does not include facilities where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds.

(b) The requirements of the Standards of Performance for Fossil-Fuel-Fired Steam Generators, 40 CFR 60, Subpart D and 326 IAC 12, are not included in the permit for the units listed in the table below for the reasons shown in the table.

Unit	Reason Not Subject
EU-1007	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41
EU-2001	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41
EU-2002	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41
EU-2003	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41
EU-2004	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41
A-602A burner	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41, whether burning acid gas in normal operation or natural gas for preheating
A-602B burner	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41, whether burning acid gas in normal operation or natural gas for preheating
A-605A tail gas incinerator	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41
A-605B tail gas incinerator	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41
HP Flare	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41
LP Flare	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41
Sulfur Block Flare	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41
Loading Flare	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41
EU-6000	Heat input capacity less than 250 MMBtu/hr
EU-7003	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41
EU-7004	Not a fossil-fuel-fired steam generating unit as defined at 40 CFR 60.41

As defined at 40 CFR 60.41: *Fossil-fuel-fired steam generating unit* means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

(c) The requirements of the Standards of Performance for Electric Utility Steam Generating Units, 40 CFR 60, Subpart Da and 326 IAC 12, are not included in the permit for the EU-3000 burners and waste heat boilers, package boiler EU-6000, and Block 7000 reformers and heat recovery boilers, because the units are not electric utility steam generating units as defined at 40 CFR 60.41Da. The units do not supply more than one-third of their potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale.

(d) 40 CFR 60, Subpart Db

(1) The requirements of the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and 326 IAC 12, are not included in the permit for the units listed in the table below for the reasons shown in the table.

Unit	Reason Not Subject
EU-1007	Not a steam generating unit as defined at 40 CFR 60.41b
EU-2001	Process heater as defined at 40 CFR 60.41b
EU-2002	Heat input capacity less than 100 MMBtu/hr and a process heater as defined at 40 CFR 60.41b
EU-2003	Heat input capacity less than 100 MMBtu/hr
A-602A burner	Process heater as defined at 40 CFR 60.41b in normal operation, not a steam generating unit when burning natural gas for preheat
A-602B burner	Process heater as defined at 40 CFR 60.41b in normal operation, not a steam generating unit when burning natural gas for preheat
A-605A tail gas incinerator	Heat input capacity less than 100 MMBtu/hr
A-605B tail gas incinerator	Heat input capacity less than 100 MMBtu/hr
HP Flare	Not a steam generating unit as defined at 40 CFR 60.41b
LP Flare	Not a steam generating unit as defined at 40 CFR 60.41b
Sulfur Block Flare	Not a steam generating unit as defined at 40 CFR 60.41b
Loading Flare	Not a steam generating unit as defined at 40 CFR 60.41b
EU-6000	Heat input capacity less than 100 MMBtu/hr
EU-7001	Process heater as defined at 40 CFR 60.41b
EU-7002	Process heater as defined at 40 CFR 60.41b

(2) The fractionator heater, EU-2004, is subject to the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and 326 IAC 12, because it is a steam generating unit as defined at 40 CFR 60.41b for which construction commenced after June 9, 1989 that has a maximum design heat input capacity of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)).

The following definitions from 40 CFR 60.41 b are applicable. *Heat transfer medium* means any material that is used to transfer heat from one point to another point. *Steam generating unit* means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart. *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.

The units subject to this rule include the following:

- One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

EU-2004 is not a process heater as defined at 40 CFR 60.41b. The unit is not 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. The unit heats material for an equilibrium stage-type separation process.

Fractionator heater EU-2004 is subject to the following portions of Subpart Db.

(A) 40 CFR 60.40b(a)
(B) 40 CFR 60.40b(c)
(C) 40 CFR 60.40b(g)
(D) 40 CFR 60.40b(j)
(E) 40 CFR 60.41b
(F) 40 CFR 60.44b(a)(1)
(G) 40 CFR 63.44b(c)
(H) 40 CFR 63.44b(e)
(I) 40 CFR 60.44b(f)
(J) 40 CFR 60.44b(h)
(K) 40 CFR 60.44b(i)
(L) 40 CFR 60.46b(a)
(M) 40 CFR 60.46b(c)
(N) 40 CFR 60.46b(e)
(O) 40 CFR 60.48b(b)
(P) 40 CFR 60.48b(c)
(Q) 40 CFR 60.48b(d)
(R) 40 CFR 60.48b(e)(2)
(S) 40 CFR 60.48b(f)
(T) 40 CFR 60.49b

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to fractionator heater EU-2004 except as otherwise specified in 40 CFR 60, Subpart Db.

(e) 40 CFR 60, Subpart Dc

(1) The requirements of the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Dc and 326 IAC 12, are not included in the permit for the units listed in the table below for the reasons shown in the table.

Unit	Reason Not Subject
EU-1007	Not a steam generating unit as defined at 40 CFR 60.41c
EU-2001	Heat input capacity greater than 100 MMBtu/hr and a process heater as defined at 40 CFR 60.41c
EU-2002	Process heater as defined at 40 CFR 60.41c
EU-2003	Heat input capacity less than 10 MMBtu/hr
EU-2004	Heat input capacity greater than 100 MMBtu/hr
A-602A burner	Process heater as defined at 40 CFR 60.41c in normal operation, not a steam generating unit when burning natural gas for preheat
A-602B burner	Process heater as defined at 40 CFR 60.41c in normal operation, not a steam generating unit when burning natural gas for preheat
HP Flare	Not a steam generating unit as defined at 40 CFR 60.41c
LP Flare	Not a steam generating unit as defined at 40 CFR 60.41c
Sulfur Block Flare	Not a steam generating unit as defined at 40 CFR 60.41c
Loading Flare	Not a steam generating unit as defined at 40 CFR 60.41c
EU-7001	Heat input capacity greater than 100 MMBtu/hr
EU-7002	Heat input capacity greater than 100 MMBtu/hr

(2) The tail gas incinerators (A-605A and A-605B) and package boiler, EU-6000, are subject to the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Dc and 326 IAC 12, because each is a steam generating unit as defined at 40 CFR 60.41c for which construction commenced after

June 9, 1989 that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h). The units subject to this rule include the following:

- One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

- One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

- One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

- One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

- One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 68.50 MMBtu/hr (HHV), exhausting to stack EU-6000.

The units are subject to the following portions of Subpart Dc.

(A) 40 CFR 60.40c(a)
(B) 40 CFR 60.40c(b)
(C) 40 CFR 60.40c(h)
(D) 40 CFR 60.41c
(E) 40 CFR 60.48c

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to boiler EU-6000 except as otherwise specified in 40 CFR 60, Subpart Dc.

(f) The requirements of the Standards of Performance for Sulfuric Acid Plants, 40 CFR 60, Subpart H and 326 IAC 12, are not included in the permit for the sulfur recovery units, because the units are not sulfuric acid production units as defined at 40 CFR 60.81(a).

(g) The requirements of the Standards of Performance for Petroleum Refineries, 40 CFR 60, Subpart J and 326 IAC 12, are not included in the permit for the flares, fuel gas combustion units, and Claus sulfur recovery plant units listed in paragraph (h), because the units commenced construction after May 14, 2007

(h) This source is subject to the Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, 40 CFR 60, Subpart Ja and 326 IAC 12, because the source is a facility engaged in producing distillate fuel oils or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives. As defined at 40 CFR 60.101a, *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

According to an applicability determination by U.S. EPA (U.S. EPA Applicability Determination Index control number J015, Mr. Edward Reich, Division of Stationary Source Enforcement, EPA to

Mr. Jim Snydor, Region 3, EPA, March 19, 1980) Subpart J was applicable to processes for converting coal to hydrocarbon liquids:

> "... The SRC II process generally utilizes a more typical refining process with the final product a liquid. This product would fall under the definition of petroleum in 60.101(b). Therefore, if any of the affected facilities mentioned in section 60.100(a) are used in this process, the NSPS for petroleum refineries would be applicable. ..."

SRC II was one of a number of direct coal liquefaction processes, including the Kohleoel process developed jointly by Ruhrkohle and VEBA. All are applications of the process invented by Friedrich Bergius in 1913 (ref: S. Vasireddy, et al., "Clean Liquid Fuels from Direct Coal Liquefaction: Chemistry, Catalysis, Technological Status and Challenges", Energy & Environmental Science, 2011(4), February 311-345; see also: Technology Status Report 010 - Coal Liquefaction, Department of Trade and Industry, London, October 1999).

The liquid phase hydrocracking (LPH) operation, gas phase hydrotreating (GPH) operation, and hydrogen production plant are not affected facilities under this subpart. These operations are not fluid catalytic cracking units (FCCU), fluid coking units (FCU), or delayed coking units. These operations are not described by the following definitions from 40 CFR 60.101a:

> *Delayed coking unit* means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors.
>
> *Fluid catalytic cracking* unit means a refinery process unit in which petroleum derivatives are continuously charged and 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 regenerated by burning off coke and other deposits.
>
> *Fluid coking unit* means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system.

LPH is a hydrogen cracking reaction, not thermal cracking, and the LPH process does not regenerate a catalyst. Hydrotreating stages in the GPH reactor are not cracking processes. Hydrotreating removes sulfur, nitrogen, oxygen, and halogens and to convert olefin and acetylene bonds to saturated forms. The GPH operation includes hydrocracking stages, which are, like the LPH process, not thermal cracking and do not regenerate catalysts.

The hydrogen plant reactors are not fuel combustion units as defined at 40 CFR 60.101a. Natural gas and fractionator overhead are supplied to the hydrogen plant as feed for a catalytic reaction to produce gaseous hydrogen used in other operations and carbon monoxide, with additional hydrogen produced from carbon monoxide by the water gas reaction. The reactions in the hydrogen plant are thus a process that creates a product rather than the combustion of a fuel to generate heat. As noted below, radiant heating sections of the reformer, where fuel gas and PSA tail gas are combusted, are not excluded from Subpart Ja. See the applicability determination by U.S. EPA (U.S. EPA Applicability Determination Index control number Z080005, Ms. Cynthia Reynolds, Region 8, EPA to Mr. Phillip Preston, Hyperion Energy, LLC, November 20, 2008).

The units subject to this rule include the following:

- One (1) natural gas and process fuel gas-fired heater, identified as Coal Dryer Heater EU-1007, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 55.8 MMBtu/hr (HHV), with emissions exhausting to Stack EU-1007.

- One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2018 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

- One (1) natural gas and process fuel gas-fired indirect treat gas heater, identified as EU-2002, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 52.8 MMBtu/hr (HHV), receiving hydrogen from Block 7000 and discharging to the 1st stage reactors, exhausting to stack EU-2002.

- One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the vacuum distillation tower, exhausting to stack EU-2003.

- One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

- One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

  (1) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

  (2) One (1) two-stage low pressure absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

- Sulfur recovery operations, identified as Block 3000, consisting of:

  (1) Amine Regeneration Unit, consisting of:

    (A) One (1) heat exchanger, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

    (B) One (1) stripper column , identified as Stripper, approved in 2018 for construction, discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger and the reboiler and vapor to the overheads condenser, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

    (C) One (1) water-cooled condenser, identified as Overheads Condenser, approved in 2018 for construction, discharging condensate to the stripper condenser accumulator, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

- (D) One (1) accumulator drum, identified as Stripper Condenser Accumulator, approved in 2018 for construction, discharging condensate to stripper reflux and the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

- (E) One (1) steam-heated reboiler, identified as Stripper Reboiler, approved in 2018 for construction, discharging lean amine to the stripper reflux, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(2) Sour Water Stripping System, consisting of:

- (A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

- (B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(3) Sulfur Recovery System, consisting of:

- (A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

    - (i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
    - (ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.
    - (iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
    - (iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the TGTU A Heat Exchanger and molten sulfur to the sulfur product pit.
    - (v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
    - (vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
    - (vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.

    - (viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
    - (ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
    - (x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
    - (xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

- (B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

    - (i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
    - (ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.
    - (iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
    - (iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.
    - (v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
    - (vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
    - (vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.
    - (viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
    - (ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
    - (x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
    - (xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

- Flares, as follows:

  (A) One (1) natural gas and process fuel gas-fired flare identified as High Pressure (HP) Flare, approved in 2018 for construction, servicing overpressure and emergency reliefs from Block 2000 VEBA Combi Cracker operations, controlling emissions from Block 2000 depressurization system, with pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

  (B) One (1) natural gas and process fuel gas-fired flare, identified as Low Pressure (LP) Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 7000 Hydrogen Unit operations, controlling emissions Block 7000 start-up and shut-down vents, and a continuous sweep stream from the Block 2000 slop tank, with a sweep and pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

  (C) One (1) natural gas and process fuel gas-fired flare, identified as Sulfur Block Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 3000 Sulfur Recovery operations and sulfur loading, controlling emergency streams from Sulfur Recovery Units A and B, and a continuous sweep stream from the sour water storage tanks, with a sweep and pilot heat input capacity of 0.77 MMBtu/hr (LHV), exhausting to the atmosphere.

  (D) One (1) natural gas and process fuel gas-fired flare, identified as Loading Flare, approved in 2018 for construction, servicing Block 4000 naphtha, diesel, and ammonia loading operations, with a pilot heat input capacity of 0.20 MMBtu/hr (LHV), exhausting to the atmosphere.

- One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 68.50 MMBtu/hr (HHV), exhausting to stack EU-6000.

- Hydrogen unit operations, identified as Block 7000, as follows:

  (1) Hydrogen Plant 1, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

    (C) One (1) reformer system, consisting of:

      (i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7001, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

  (2) Hydrogen Plant 2, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

    (C) One (1) reformer system, consisting of:

      (i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7002, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

This source is subject to the following portions of Subpart Ja.

(1) 40 CFR 60.100a
(2) 40 CFR 60.101a
(3) 40 CFR 60.102a(a)
(4) 40 CFR 60.102a(f)(1)
(5) 40 CFR 60.102a(g)
(6) 40 CFR 60.103a(a)
(7) 40 CFR 60.103a(b)
(8) 40 CFR 60.103a(c)
(9) 40 CFR 60.103a(d)
(10) 40 CFR 60.103a(e)
(11) 40 CFR 60.103a(h)
(12) 40 CFR 60.103a(j)
(13) 40 CFR 60.104a(a)
(14) 40 CFR 60.104a(c)
(15) 40 CFR 60.104a(h)
(16) 40 CFR 60.104a(i)
(17) 40 CFR 60.104a(j)
(18) 40 CFR 60.106a
(19) 40 CFR 60.107a(a)
(20) 40 CFR 60.107a(b)
(21) 40 CFR 60.107a(c)
(22) 40 CFR 60.107a(d)
(23) 40 CFR 60.107a(e)
(24) 40 CFR 60.107a(f)
(25) 40 CFR 60.107a(g)
(26) 40 CFR 60.107a(i)
(27) 40 CFR 60.108a
(28) 40 CFR 60.109a

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the source except as otherwise specified in 40 CFR 60, Subpart Ja.

(i) The requirements of the Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978, 40 CFR 60, Subpart K and 326 IAC 12, are not included in the permit for the storage vessels listed in paragraph (k), because the units commenced construction after May 19, 1978.

(j) The requirements of the Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984, 40 CFR 60, Subpart Ka and 326 IAC 12, are not included in the permit for the storage vessels listed in paragraph (k), because the units commenced construction after July 23, 1984.

(k) This source is subject to 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 60, Subpart Kb and 326 IAC 12, because construction of the storage vessels commenced after July 23, 1984. Applicability of this subpart to each storage vessel is discussed in the table below:

ID	Contents	Capacity (gallons) (m^3)	Subject	Not Subject	Reason Not Subject
T1	Naphtha product	4,629,879 (17,524)	X		
T2	Naphtha product	4,629,879 (17,524)	X		
T3	Diesel product	4,525,796 (17,130)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T4	Diesel product	4,525,796 (17,130)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T5	Diesel product	4,525,796 (17,130)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T6	Naphtha or diesel product	4,629,879 (17,524)	X		
T7	Molten sulfur	342,367 (1,296)		X	contents not volatile organic liquid (40 CFR 60.111b)
T8	Molten sulfur	342,367 (1,296)		X	contents not volatile organic liquid (40 CFR 60.111b)
T9	Ammonia product (pressurized)	36,720 (17,524)		X	pressure vessel (40 CFR 60.110b(c)(2))
T10	Residue surge tank 1	926,980 (17,524)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T11	Residue surge tank 2	926,980 (3,509)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T12	Residue feed tank	926,980 (3,509)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T13	VGO tank 1	926,980 (3,509)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T14	VGO tank 2	926,980 (3,509)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T15	LPG storage (pressurized)	48,872 (185)		X	pressure vessel (40 CFR 60.110b(c)(2))
T16	Slop tank	4,195,581 (15,880)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T17	Diesel fuel tank	23,775 (90)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T18	Non-phenolic sour water storage tank 1	1,268,026 (4,799)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T19	Non-phenolic sour water storage tank 2	1,268,026 (4,799)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T20	Non-phenolic sour water storage tank 3	1,268,026 (4,799)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)

ID	Contents	Capacity (gallons) (m^3)	Subject	Not Subject	Reason Not Subject
T21	Phenolic sour water storage tank	40,947 (155)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T22	Stripped non-phenolic sour water surge tank	1,268,026 (4,799)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T23	Stripped phenolic sour water surge tank	13,737 (52)		X	Capacity less than 75 m^3 (40 CFR 60.110b(a)
T24	Amine surge/deinventory tank	63,943 (242)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T25	Fresh amine tank	63,943 (242)		X	maximum true vapor pressure less than 3.5 kPa (40 CFR 60.110b(b)
T26	Amine containment tank	793 (3)		X	Capacity less than 75 m^3 (40 CFR 60.110b(a)
EU-6005	Emergency generator diesel fuel tank	2,000 (8) (nominal)		X	Capacity less than 75 m^3 (40 CFR 60.110b(a)
EU-6007	Emergency fire pump diesel tank	500 (2) (nominal)		X	Capacity less than 75 m^3 (40 CFR 60.110b(a)

Tanks T1, T2, and T6 are subject to the following portions of Subpart Kb.

(1) 40 CFR 60.110b(a)
(2) 40 CFR 60.110b(e)
(3) 40 CFR 60.111b
(4) 40 CFR 60.112b(a)(1)
(5) 40 CFR 60.113b(a)
(6) 40 CFR 60.114b
(7) 40 CFR 60.115b(a)
(8) 40 CFR 60.116b
(9) 40 CFR 60.117b

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to tanks T1, T2, and T6 except as otherwise specified in 40 CFR 60, Subpart Kb.

(l) The source is subject to the Standards of Performance for Coal Preparation and Processing Plants, 40 CFR 60, Subpart Y and 326 IAC 12, because Block 1000 is a coal preparation and processing plant as defined at 40 CFR 60.251(e) that commenced construction after May 27, 2009. The units subject to this rule include the following:

- Coal handling operations, identified as Block 1000, consisting of:

  (1) One (1) shelter-type railcar dump unloading facility, identified as EU-1000, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1000, exhausting to stack EU-1000, consisting of:

    (A) Two (2) enclosed receiving pits, identified as Receiving Pit 1 and Receiving Pit 2, discharging to Receiving Bin 1 and Receiving Bin 2, respectively.

(B) Two (2) enclosed receiving bins, identified as Receiving Bin 1 and Receiving Bin 2, discharging to Drag Flight Feeder 1 and Drag Flight Feeder 2, respectively, with water spray dust suppression systems.

(C) Two (2) enclosed drag flight feeders, identified as Drag Flight Feeder 1 and Drag Flight Feeder 2, discharging to the Unloading Conveyor, with water spray dust suppression systems.

(2) One (1) enclosed rail unloading conveyor discharging to Transfer Station 1, identified as Unloading Conveyor, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

(3) One (1) enclosed transfer station discharging to Conveyor 1, Conveyor 2, or Conveyor 9, identified as Transfer Station (EU-1001), approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

(4) One (1) enclosed feed conveyor discharging to Stacker 1 Boom Conveyor/Chute, identified as Conveyor 1, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

(5) One (1) enclosed stacker boom conveyor discharging to Coal Stockpiles #1A & #1B, identified as Stacker 1 Boom Conveyor/Chute, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

(6) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #1A and Stockpile #1B, with a maximum capacity of 93,000 tons, controlled by the coal storage pile enclosure and baghouse EU-1006.

(7) One (1) enclosed feed conveyor discharging to Stacker 2 Boom Conveyor/Chute, identified as Conveyor 2, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

(8) One (1) enclosed stacker boom conveyor/chute discharging to Stockpiles #2A & #2B, identified as Stacker 2 Boom Conveyor/Chute, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

(9) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #2A and Stockpile #2B, with a maximum capacity of 93,000 tons, controlled by the coal storage pile enclosure and baghouse EU-1006.

(10) One (1) reclaimer for Stockpiles #1A & #1B, discharging to Reclaim Conveyor 6, identified as Reclaimer 1, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with emissions controlled by the coal pile total enclosure and Baghouse EU-1006.

(11) One (1) enclosed reclaimer conveyor, identified as Conveyor 6 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

(12) One (1) reclaimer for Stockpiles #2A & #2B, discharging to Reclaime Conveyor 7, identified as Reclaimer 2, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

(13) One (1) enclosed reclaimer conveyor, identified as Conveyor 7, discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

(14) One (1) enclosed transfer station conveyor, identified as Conveyor 9 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

(15) One (1) enclosed reclaim transfer structure discharging to Reclaim Conveyor 8, identified as Reclaim Transfer Station (EU-1006), approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

(17) One (1) enclosed coal mill conveyor, identified as Reclaim Conveyor 8, discharging to the Coal Mill and Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with emissions controlled the Coal Dryer Baghouse.

- Coal drying loop, collectively identified as EU-1008, with emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008, consisting of the following:

(1) One (1) enclosed coal mill and pulverizer, identified as Coal Mill and Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer, with particulate emissions controlled the Coal Dryer Baghouse.

(2) One (1) enclosed coal dryer, identified as Coal Dryer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer Baghouse, with particulate emissions controlled by the Coal Dryer Baghouse.

(3) One (1) natural gas and process fuel gas-fired heater, identified as Coal Dryer Heater EU-1007, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 55.8 MMBtu/hr (HHV), with emissions exhausting to Stack EU-1007.

(4) One (1) process baghouse, identified as Coal Dryer Baghouse, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging fines to the Block 2000 Coal Hopper, exhausting particulate and filtered nitrogen to the condenser.

(5) One (1) water-cooled condenser, identified as Drying Loop Condenser, approved in 2018 for construction, with a nominal capacity of 40 MMBtu/hr, controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008.

- VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(1) One (1) enclosed hopper receiving coal from Block 1000 Coal Dryer Baghouse and discharging to the Feed Prep Screw Conveyor, identified as Coal Hopper, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year.

(2) One (1) enclosed screw conveyor, identified as Closed Screw Conveyor, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Feed Premix Drum, identified as Closed Screw Conveyor, with particulate emissions controlled by the Coal Handling System Filter, exhausting to stack EU-2005.

The units are subject to the following portions of Subpart Y.

(1) 40 CFR 60.250(a)
(2) 40 CFR 60.250(d)
(3) 40 CFR 60.251
(4) 40 CFR 60.252(b)(1)
(5) 40 CFR 60.252(b)(2)(iii)
(6) 40 CFR 60.252(b)(3)
(7) 40 CFR 60.252(c)
(8) 40 CFR 60.254(b)
(9) 40 CFR 60.255(b)
(10) 40 CFR 60.255(c)
(11) 40 CFR 60.255(d)
(12) 40 CFR 60.255(e)
(13) 40 CFR 60.255(f)
(14) 40 CFR 60.255(g)
(15) 40 CFR 60.256(b)
(16) 40 CFR 60.256(c)
(17) 40 CFR 60.257
(18) 40 CFR 60.258

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the units except as otherwise specified in 40 CFR 60, Subpart Y.

(m) The requirements of the Standards of Performance for Metallic Mineral Processing Plants, 40 CFR 60, Subpart LL and 326 IAC 12, are not included in the permit for Block 1500 additive handling and storage operations, the Block 2000 additive preparation operations, or the Block 6500 lime handling and storage operations because the operations are not a metallic mineral processing plant as defined at 40 CFR 60.381. The operations do not produce metallic mineral concentrates from ores.

(n) The requirements of the Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006, 40 CFR 60, Subpart VV and 326 IAC 12, are not included in the permit for the source, because the source commenced construction after November 7, 2006.

(o) The requirements of the Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, 40 CFR 60, Subpart VVa and 326 IAC 12, are not included in the permit for the source, because the source is not in the synthetic organic chemical manufacturing industry as defined at 40 CFR 60.481a. The source does not produce, as an intermediate or final product, one or more of the chemicals listed in 40 CFR 60.489.

(p) The requirements of the Standards of Performance for Bulk Gasoline Terminals, 40 CFR 60, Subpart XX and 326 IAC 12, are not included in the permit for the Product Loading Rack, because the source is not a bulk gasoline terminal as defined at 40 CFR 60.501. The source does not receive gasoline by pipeline, ship, or barge.

(q) The requirements of the Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006, 40 CFR 60, Subpart GGG and 326 IAC 12, are not included in the permit for this source, because the source commenced construction after November 7, 2006.

(r) This source is subject to the Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, 40 CFR 60, Subpart GGGa and 326 IAC 12, because the source is a facility engaged in producing distillate fuel oils or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives. As defined at 40 CFR 60.591a, *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

The treat gas heater, EU-2002, is not in VOC service. The fluid stream heated in the unit can be reasonably expected always to exceed 50 percent hydrogen by volume. Therefore Subpart GGGa is not applicable to this unit.

The facilities subject to this rule include the group of all the equipment (defined in § 60.591a) within each of the following process units:

- VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

  (5) One (1) nitrogen-blanketed Na_2S slurry preparation system, identified as Na_2S Slurry Preparation, approved in 2018 for construction, with a maximum capacity of 0.077 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Na_2S Handling System Filter, exhausting to stack EU-2008, consisting of:

    (C) One (1) nitrogen-blanketed mixing drum for Na_2S and Block 2000 vacuum tower VGO (vacuum gas oil) discharging to the feed premix drum.

  (6) One (1) feed premix drum, identified as Feed Premix Drum, approved in 2018 for construction, receiving coal, solid additives, and recycled vacuum gas oil (VGO) and discharging to the feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

  (7) One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2018 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

  (9) One (1) first stage reactor - liquid phase hydrocracking system, identified as LPH, approved in 2018 for construction, discharging to the hot separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

  (10) One (1) hot separator, identified as Hot Separator, approved in 2018 for

construction, discharging vapor to the 2nd stage reactors and liquids to the vacuum column feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

(11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the vacuum distillation tower, exhausting to stack EU-2003

(12) One (1) vacuum distillation tower, identified as Vacuum Distillation Column, approved in 2018 for construction, discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 4000, phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

(13) One (1) second stage reactor - gas phase hydrotreating system, identified as GPH, approved in 2018 for construction, discharging to the cold separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

(14) One (1) cold separator , identified as Cold Separator, approved in 2018 for construction, discharging non-phenolic sour water to Block 3000 and hydrocarbons to the fractionator heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

(16) One (1) fractionator tower, identified as Fractionator Tower, approved in 2018 for construction, discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix Drum, and non-phenolic sour water to Block 3000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

(A) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

- Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

(A) One (1) heat exchanger, identified as Rich Amine-Lean Amine Heat

Exchanger, approved in 2018 for construction, where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) stripper column , identified as Stripper, approved in 2018 for construction, discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger and the reboiler and vapor to the overheads condenser, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(C) One (1) water-cooled condenser, identified as Overheads Condenser, approved in 2018 for construction, discharging condensate to the stripper condenser accumulator, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(D) One (1) accumulator drum, identified as Stripper Condenser Accumulator, approved in 2018 for construction, discharging condensate to stripper reflux and the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(E) One (1) steam-heated reboiler, identified as Stripper Reboiler, approved in 2018 for construction, discharging lean amine to the stripper reflux, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(3) Sulfur Recovery System, consisting of:

(A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.

(ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.

(iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.

(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the TGTU A Heat Exchanger and molten sulfur to the sulfur product pit.

(v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.

(vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.

(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.

(viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.

(ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.

(x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.

(ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.

(iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.

(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.

(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.

(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.

(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.

(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.

(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.

(x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

- Offsites operations, identified as Block 4000, consisting of:

(1) Flares, as follows:

(A) One (1) natural gas and process fuel gas-fired flare identified as High Pressure (HP) Flare, approved in 2018 for construction, servicing overpressure and emergency reliefs from Block 2000 VEBA Combi Cracker operations, controlling emissions from Block 2000 depressurization system, with pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(B) One (1) natural gas and process fuel gas-fired flare, identified as Low Pressure (LP) Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 7000 Hydrogen Unit operations, controlling emissions Block 7000 start-up and shut-down vents, and a continuous sweep stream from the Block 2000 slop tank, with a sweep and pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(C) One (1) natural gas and process fuel gas-fired flare, identified as Sulfur Block Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 3000 Sulfur Recovery operations and sulfur loading, controlling emergency streams from Sulfur Recovery Units A and B, and a continuous sweep stream from the sour water storage tanks, with a sweep and pilot heat input capacity of 0.77 MMBtu/hr (LHV), exhausting to the atmosphere.

(D) One (1) natural gas and process fuel gas-fired flare, identified as Loading Flare, approved in 2018 for construction, servicing Block 4000 naphtha, diesel, and ammonia loading operations, with a pilot heat input capacity of 0.20 MMBtu/hr (LHV), exhausting to the atmosphere.

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)
T1	IFR	Naphtha product	4,629,879 (17,524)
T2	IFR	Naphtha product	4,629,879 (17,524)
T3	FR	Diesel product	4,525,796 (17,130)

ID	Construction[1]	Contents	Capacity (gallons) (m^3)
T4	FR	Diesel product	4,525,796 (17,130)
T5	FR	Diesel product	4,525,796 (17,130)
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)
T10	FR	Residue surge tank 1	926,980 (17,524)
T11	FR	Residue surge tank 2	926,980 (3,509)
T12	FR	Residue feed tank	926,980 (3,509)
T13	FR	VGO tank 1	926,980 (3,509)
T14	FR	VGO tank 2	926,980 (3,509)
T15	FR	LPG storage (pressurized)	48,872 (185)

Notes:
1. FR - fixed roof, IFR - internal floating roof

(3) Loading operations, as follows:

(A) One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

- Hydrogen unit operations, identified as Block 7000, as follows:

(1) Hydrogen Plant 1, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

(B) One (1) feed preparation train, identified as Feed Prep 1, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7001, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 1, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

(2) Hydrogen Plant 2, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

(B) One (1) feed preparation train, identified as Feed Prep 2, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7002, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 2, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

Note: Pursuant to 40 CFR 60.590a(e), owners or operators are not required to comply with the definition of “process unit” in § 60.591 of this subpart until the EPA takes final action to require compliance and publishes a document in the Federal Register. While the definition of “process unit” is stayed, owners or operators should use the following definition:

> *Process unit* means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

This exclusion affects storage vessels, product transfer racks, and connected ducts and piping.

This source is subject to the following portions of Subpart GGGa.

(1) 40 CFR 60.590a
(2) 40 CFR 60.591a
(3) 40 CFR 60.592a
(4) 40 CFR 60.593a

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the source except as otherwise specified in 40 CFR 60, Subpart GGGa.

(s) The vacuum distillation tower and fractionator tower are subject to the Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations, 40 CFR 60, Subpart NNN and 326 IAC 12, because the units are part of a process unit that produces one or more of the chemicals listed in 40 CFR 60.667 as a product, co-product, byproduct, or intermediate. The units subject to this rule include the following:

- One (1) vacuum distillation tower, identified as Vacuum Distillation Column, approved in 2018 for construction, discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 4000, phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

- One (1) fractionator tower, identified as Fractionator Tower, approved in 2018 for construction, discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix Drum, and non-phenolic sour water to Block 3000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

The vacuum distillation tower and fractionator tower are subject to the following portions of Subpart NNN.

(1) 40 CFR 60.660(a)
(2) 40 CFR 60.660(b)(3)
(3) 40 CFR 60.660(c)(4)
(4) 40 CFR 60.661
(5) 40 CFR 60.662
(6) 40 CFR 60.663(f)
(7) 40 CFR 60.664
(8) 40 CFR 60.665
(9) 40 CFR 60.666
(10) 40 CFR 60.667
(11) 40 CFR 60.668

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the vacuum distillation tower and fractionator tower except as otherwise specified in 40 CFR 60, Subpart NNN.

(y) 40 CFR 60, Subpart OOO

(1) The requirements of the Standards of Performance for Nonmetallic Mineral Processing Plants, 40 CFR 60, Subpart OOO and 326 IAC 12, are not included in the permit for the enclosed coal mill and pulverizer, because coal is not a nonmetallic mineral as defined at 40 CFR 60.671.

(2) The requirements of the Standards of Performance for Nonmetallic Mineral Processing Plants, 40 CFR 60, Subpart OOO and 326 IAC 12, are not included in the permit for the operations listed in the table below, because the units are not nonmetallic mineral processing plants as defined at 40 CFR 60.671. The units are not equipment that is used to crush or grind any nonmetallic mineral as defined at 40 CFR 60.671.

Units Not Subject to Subpart OOO
Three (3) pneumatic (nitrogen) truck unloading systems discharging to storage silos, identified as Sodium Sulfide (Na_2S) Unloading, Fine Additive Unloading, and Coarse Additive Unloading
One (1) Na_2S silo, identified as T35
One (1) fine additive silo, identified as T33
One (1) coarse additive silo
One (1) enclosed screw conveyor discharging to the Feed Premix Drum, identified as Closed Screw Conveyor
One (1) nitrogen-blanketed Na_2S slurry preparation system
One (1) nitrogen-blanketed fine additive transfer system discharging to the Block 2000 feed premix drum, identified as Fine Additive Transfer
One (1) feed premix drum receiving coal, solid additives, and recycled vacuum gas oil (VGO)

Units Not Subject to Subpart OOO
Block 6500 pneumatic lime truck unloading system
One (1) lime storage silo, identified as EU-6501

(3) The requirements of the Standards of Performance for Nonmetallic Mineral Processing Plants, 40 CFR 60, Subpart OOO and 326 IAC 12, are not included in the permit for the Block 1500 fine additive production system, because the unit is not a nonmetallic mineral processing plant as defined at 40 CFR 60.671. The unit does not crush or grind any nonmetallic mineral listed in 40 CFR 60.671 or a mixture of which the majority is any of the listed minerals. The solid additive is predominantly a byproduct of bauxite processing commonly known as red mud.

(u) This source is subject to the Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems, 40 CFR 60, Subpart QQQ and 326 IAC 12, because the source is a petroleum refinery for which construction commenced after May 4, 1987. The units subject to this rule include the following:

Pursuant to 40 CFR 63.640(o)(1), a Group 1 wastewater stream managed in a piece of equipment that is also subject to the provisions of 40 CFR 63, Subpart CC is required to comply only with that subpart.

- Offsites operations, identified as Block 4000, consisting of:

  (2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T16	FR	Slop tank	4,195,581 (15,880)	LP flare

1. FR - fixed roof, IFR - internal floating roof, HPV-horizontal pressure vessel
2. Tank vents to flares are part of sweep and pilot gas streams.

- Wastewater treatment operations, identified as Block 8000, as follows:

  (1) One (1) wastewater junction box with associated process drains, identified as Oily Water Sump, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8002.

  (2) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Water Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and water to MH1.

  (3) One (1) wastewater junction box with, identified as MH1, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8003.

  (4) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Amine Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and amine solution to the Rich Amine Return Header.

  (5) One (1) biological wastewater treatment system, approved in 2018 for construction, with emissions exhausting to vent EU-8001.

This source is subject to the following portions of Subpart QQQ.

(1) 40 CFR 60.690

(2) 40 CFR 60.691
(3) 40 CFR 60.692-1
(4) 40 CFR 60.692-2
(5) 40 CFR 60.692-3
(6) 40 CFR 60.692-4
(7) 40 CFR 60.692-5
(8) 40 CFR 60.692-6
(9) 40 CFR 60.692-7
(10) 40 CFR 60.693-1
(11) 40 CFR 60.693-2
(12) 40 CFR 60.694
(13) 40 CFR 60.695
(14) 40 CFR 60.696
(15) 40 CFR 60.697
(16) 40 CFR 60.698
(17) 40 CFR 60.699

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the source except as otherwise specified in 40 CFR 60, Subpart QQQ.

(v) The first stage reactor - liquid phase hydrocracking system and second stage reactor - gas phase hydrotreating system are subject to the Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes, 40 CFR 60, Subpart RRR and 326 IAC 12, because the units are reactor processes that are part of a process unit that that produces one or more of the chemicals listed in 40 CFR 60.707 as a product, co-product, byproduct, or intermediate. The source will produce benzene, which is listed in 40 CFR 60.707, as a byproduct of the VCC process. The units subject to this rule include the following:

- One (1) first stage reactor - liquid phase hydrocracking system, identified as LPH, approved in 2018 for construction, discharging to the hot separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

- One (1) second stage reactor - gas phase hydrotreating system, identified as GPH, approved in 2018 for construction, discharging to the cold separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

The first stage reactor - liquid phase hydrocracking system and second stage reactor - gas phase hydrotreating system are subject to the following portions of Subpart RRR.

(1) 40 CFR 60.700(a)
(2) 40 CFR 60.700(b)(3)
(3) 40 CFR 60.700(c)(5)
(4) 40 CFR 60.701
(5) 40 CFR 60.705(r)
(6) 40 CFR 60.706
(7) 40 CFR 60.707
(8) 40 CFR 60.708

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the first stage reactor - liquid phase hydrocracking system and second stage reactor - gas phase hydrotreating system except as otherwise specified in 40 CFR 60, Subpart RRR.

(w) The emergency generator and emergency fire pump are subject to the Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII and 326 IAC 12, because the units are stationary compression ignition internal combustion engines that commenced construction after July 11, 2005.

Based on this evaluation, this source is subject to 40 CFR 60, Subpart IIII. On May 4, 2016, the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating paragraphs 40 CFR 60.4211(f)(2)(ii) - (iii) of NSPS Subpart IIII. Therefore, these paragraphs no longer have any legal effect and any engine that is operated for purposes specified in these paragraphs becomes a non-emergency engine and must comply with all applicable requirements for a non-emergency engine.

For additional information, please refer to the USEPA's Guidance Memo:
https://www.epa.gov/sites/production/files/2016-06/documents/ricevacaturguidance041516.pdf

Since the federal rule has not been updated to remove these vacated requirements, the text below shows the vacated language as ~~strikethroug~~h text. At this time, IDEM is not making any changes to the permit's attachment due to this vacatur. However, the permit will not reference the vacated requirements, as applicable.

40 CFR 60.4211(f)(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraph~~s~~ (f)(2)(i) ~~through (iii)~~ of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

~~(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.~~

~~(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.~~

The units subject to this rule include the following:

- One (1) diesel engine-driven emergency generator, identified as EU-6006, approved in 2018 for construction, with a maximum heat input capacity of 19.60 MMBtu/hr (2,800 hp) (average heating value), using no add-on controls and exhausting to stack EU-6006.

- One (1) diesel engine-driven emergency fire pump, identified as EU-6008, approved in 2018 for construction, with a maximum heat input capacity of 5.25 MMBtu/hr (750 hp) (average heating value), using no add-on controls and exhausting to stack EU-6008.

The units are subject to the following portions of Subpart IIII.

(1) 40 CFR 60.4200(a)(2)
(2) 40 CFR 60.4200(a)(4)
(3) 40 CFR 60.4205(b)
(4) 40 CFR 60.4205(c)
(5) 40 CFR 60.4206

(6) 40 CFR 60.4207(b)
(7) 40 CFR 60.4208(a)
(8) 40 CFR 60.4209(a)
(9) 40 CFR 60.4211(a)
(10) 40 CFR 60.4211(c)
(11) 40 CFR 60.4211(f)(1)
(12) 40 CFR 60.4211(f)(2)(i)
(13) 40 CFR 60.4211(f)(3)
(14) 40 CFR 60.4211(g)(2)
(15) 40 CFR 60.4211(g)(3)
(16) 40 CFR 60.4214(b)
(17) 40 CFR 60.4218
(18) 40 CFR 60.4219
(19) Table 4 to Subpart IIII of Part 60
(20) Table 5 to Subpart IIII of Part 60
(21) Table 8 to Subpart IIII of Part 60

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the emergency generator and emergency fire pump except as otherwise specified in 40 CFR 60, Subpart IIII.

(x) There are no other New Source Performance Standards (40 CFR Part 60) and 326 IAC 12 included in the permit for this proposed new source.

National Emission Standards for Hazardous Air Pollutants (NESHAP):

(a) The requirements of the National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene, 40 CFR 61, Subpart J, 326 IAC 14-7 are not included in the permit. The source has no equipment in benzene service as defined at 40 CFR 61.111. *In benzene service* means that a piece of equipment either contains or contacts a fluid (Liquid or gas) that is at least 10 percent benzene by weight as determined according to the provisions of §61.245(d). The provisions of §61.245(d) also specify how to determine that a piece of equipment is not in benzene service. Based on information provided by the licensor, the benzene content of products is expected to be less than 2% by weight

(b) The requirements of the National Emission Standard for Equipment Leaks (Fugitive Emission Sources), 40 CFR 61, Subpart V, 326 IAC 14-8-1 are not included in the permit. The source is not subject to provisions of 40 CFR 61 that reference this subpart.

(c) The loading rack, is subject to the National Emission Standard for Benzene Emissions From Benzene Transfer Operations, 40 CFR 61, Subpart BB, when loading naphtha because the unit is a loading rack at which naphtha product containing benzene is loaded into railcars. Based on information provided by the licensor, the benzene content of products is expected to be less than 2% by weight. The units subject to this rule include the following:

- One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

The Product Loading Rack is subject to the following portions of Subpart BB:

(1) 40 CFR 61.300(a)
(2) 40 CFR 61.300(b)
(3) 40 CFR 61.305(i)

(d) This source is subject to the National Emission Standards for Benzene Waste Operations, 40 CFR 61, Subpart FF, because the source is a petroleum refinery as defined in 40 CFR 61.341. The units subject to this rule include the following:

- Sulfur recovery operations, identified as Block 3000, consisting of:
  - (1) Sour Water Stripping System, consisting of:
    - (A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.
    - (B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.
- Offsites operations, identified as Block 4000, consisting of:
  - (1) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T16	FR	Slop tank	4,195,581 (15,880)	LP flare
T18	FR	Non-phenolic sour water storage tank 1	1,268,026 (4,799)	SB flare
T19	FR	Non-phenolic sour water storage tank 2	1,268,026 (4,799)	SB flare
T20	FR	Non-phenolic sour water storage tank 3	1,268,026 (4,799)	SB flare
T21	FR	Phenolic sour water storage tank	40,947 (155)	SB flare

- Wastewater treatment operations, identified as Block 8000, as follows:
  - (1) One (1) wastewater junction box with associated process drains, identified as Oily Water Sump, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8002.
  - (2) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Water Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and water to MH1.
  - (3) One (1) wastewater junction box with, identified as MH1, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8003.
  - (4) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Amine Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and amine solution to the Rich Amine Return Header.
  - (5) One (1) biological wastewater treatment system, approved in 2018 for construction, with emissions exhausting to vent EU-8001.

This source is subject to the following portions of Subpart FF:

(1) 40 CFR 61.340
(2) 40 CFR 61.341
(3) 40 CFR 61.342
(4) 40 CFR 61.343
(5) 40 CFR 61.346
(6) 40 CFR 61.347
(7) 40 CFR 61.348
(8) 40 CFR 61.349
(9) 40 CFR 61.350
(10) 40 CFR 61.351
(11) 40 CFR 61.352
(12) 40 CFR 61.353
(13) 40 CFR 61.354
(14) 40 CFR 61.355
(15) 40 CFR 61.356
(16) 40 CFR 61.357
(17) 40 CFR 61.358

The requirements of 40 CFR Part 61, Subpart A – General Provisions, which are incorporated as 326 IAC 14-1, apply to the source except as otherwise specified in 40 CFR 61, Subpart FF.

(e) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) From the Synthetic Organic Chemical Manufacturing Industry, 40 CFR 63, Subpart F and 326 IAC 20-11 are not included in the permit for this source, since the source does not manufacture as a primary product one or more of the chemicals listed in 40 CFR 63.100(b)(1)(i) or(ii).

(f) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) From the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater, 40 CFR 63, Subpart G and 326 IAC 20-11 are not included in the permit for this source, since the source is not subject to 40 CFR 63, Subpart F.

(g) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) From the Synthetic Organic Chemical Manufacturing Industry for Equipment Leaks, 40 CFR 63, Subpart H, 326 IAC 20-11, and 326 IAC 20-12 are not included in the permit. The source is not subject to provisions of 40 CFR 63, Subpart CC that reference this subpart. Pursuant to 40 CFR 63.640(p)(2), equipment leaks subject to 40 CFR 63, Subpart CC that are also subject to 40 CFR 60, Subpart GGGa are required to comply only with the provisions specified in 40 CFR 60, Subpart GGGa.

(h) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial Process Cooling Towers, 40 CFR 63, Subpart Q and 326 IAC 20-4 are not included in the permit for the cooling tower (EU-6001, EU-6002, and EU-6003), since the cooling towers are not operated with chromium-based water treatment chemicals.

(i) The requirements of the National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), 40 CFR 63, Subpart R and 326 IAC 20-10 are not included in the permit for the source, since the source is not a bulk gasoline terminal or a pipeline breakout station. The source does not receive gasoline by pipeline, ship or barge. The source is not a facility along a pipeline containing storage vessels used to relieve surges or receive and store gasoline from the pipeline for reinjection and continued transportation by pipeline or to other facilities.

(j) The requirements of the National Emission Standards for Marine Tank Vessel Loading Operations, 40 CFR 63, Subpart Y and 326 IAC 20-17 are not included in the permit for the source, since the source is not a marine tank vessel loading operation as defined at 40 CFR 63.561.

(k) This source is subject to the National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, 40 CFR 63, Subpart CC and 326 IAC 20-16, because the units are petroleum refining process units as defined at 40 CFR 63.641.

This subpart includes a definition of "petroleum refining process units" at 40 CFR 63.641:

> *Petroleum refining process unit* means a process unit used in an establishment primarily engaged in petroleum refining as defined in the Standard Industrial Classification code for petroleum refining (2911), and used primarily for the following:
>
> (1) Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants;
>
> (2) Separating petroleum; or
>
> (3) Separating, cracking, reacting, or reforming intermediate petroleum streams.
>
> (4) Examples of such units include, but are not limited to, petroleum-based solvent units, alkylation units, catalytic hydrotreating, catalytic hydrorefining, catalytic hydrocracking, catalytic reforming, catalytic cracking, crude distillation, lube oil processing, hydrogen production, isomerization, polymerization, thermal processes, and blending, sweetening, and treating processes. Petroleum refining process units also include sulfur plants.

The source self-selected an SIC code other than 2911. IDEM considers that the source conforms to all three of the uses specified in paragraphs (1) through (3) and that the source includes several of the processes named in paragraph (4). The definition of SIC code 2911, petroleum refining, from the 1987 SIC Manual is: "Establishments primarily engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, and lubricants, through fractionation or straight distillation of crude oil, redistillation of unfinished petroleum derivatives, cracking or other processes." IDEM recognizes that the source will not distill crude oil, if the term is limited to naturally occurring crude oil extracted from wells. However, the application of "cracking" in the SIC code definition is not qualified with modifying phrases like "of crude oil" or "of unfinished petroleum derivatives." It follows then that vacuum distillation of the liquid phase hydrocracking reactor product is redistillation of unfinished petroleum derivatives because the liquid supplied to the LPH reactor is recycled vacuum gas oil from the fractionator tower. The fractionation tower is itself a redistillation operation because the feed to gas phase hydrotreating reactor consists of unfinished petroleum derivatives that are hydrocracked in the LPH process.

IDEM finds that the direct coal hydrogenation process is an example of cracking or other processes in petroleum refining and that the definition of "petroleum refining process units" in 40 CFR 63.641 is clearly applicable to the source. This determination is consistent with the definitions of "petroleum" and "petroleum refining" in 40 CFR 60.101a, and the EPA determination regarding applicability of the NSPS, 40 CFR 60, Subpart J, to the production of liquid transportation fuels from coal cited in the discussion of the applicability of 40 CFR 60, Subpart Ja to the source.

The treat gas heater, EU-2002, is part of a petroleum refining process unit. However the unit is not considered to emit or have equipment containing or contacting one or more of the hazardous air pollutants listed in table 1 of this Subpart CC. Therefore Subpart CC is not applicable to this unit.

The units subject to this rule include the following:

- VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

  (5) One (1) nitrogen-blanketed Na_2S slurry preparation system, identified as Na_2S Slurry Preparation, approved in 2018 for construction, with a maximum capacity of 0.077 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Na_2S Handling System Filter, exhausting to stack EU-2008, consisting of:

    (C) One (1) nitrogen-blanketed mixing drum for Na_2S and Block 2000 vacuum tower VGO (vacuum gas oil) discharging to the feed premix drum.

  (6) One (1) feed premix drum, identified as Feed Premix Drum, approved in 2018 for construction, receiving coal, solid additives, and recycled vacuum gas oil (VGO) and discharging to the feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

  (7) One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2018 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

  (9) One (1) first stage reactor - liquid phase hydrocracking system, identified as LPH, approved in 2018 for construction, discharging to the hot separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

  (10) One (1) hot separator, identified as Hot Separator, approved in 2018 for construction, discharging vapor to the 2nd stage reactors and liquids to the vacuum column feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

  (11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the vacuum distillation tower, exhausting to stack EU-2003

  (12) One (1) vacuum distillation tower, identified as Vacuum Distillation Column, approved in 2018 for construction, discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 4000, phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

  (13) One (1) second stage reactor - gas phase hydrotreating system, identified as GPH, approved in 2018 for construction, discharging to the cold separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

  (14) One (1) cold separator , identified as Cold Separator, approved in 2018 for construction, discharging non-phenolic sour water to Block 3000 and hydrocarbons to the fractionator heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

  (15) One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

(16) One (1) fractionator tower, identified as Fractionator Tower, approved in 2018 for construction, discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix Drum, and non-phenolic sour water to Block 3000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

    (A) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

    (B) One (1) two-stage low pressure absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

- Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

    (A) One (1) heat exchanger, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

    (B) One (1) stripper column , identified as Stripper, approved in 2018 for construction, discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger and the reboiler and vapor to the overheads condenser, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

    (C) One (1) water-cooled condenser, identified as Overheads Condenser, approved in 2018 for construction, discharging condensate to the stripper condenser accumulator, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

    (D) One (1) accumulator drum, identified as Stripper Condenser Accumulator, approved in 2018 for construction, discharging condensate to stripper reflux and the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

    (E) One (1) steam-heated reboiler, identified as Stripper Reboiler, approved in 2018 for construction, discharging lean amine to the stripper reflux, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(3) Sulfur Recovery System, consisting of:

(A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the TGTU A Heat Exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
(xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
(xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

- Offsites operations, identified as Block 4000, consisting of:

(1) Flares, as follows:

(A) One (1) natural gas and process fuel gas-fired flare identified as High Pressure (HP) Flare, approved in 2018 for construction, servicing overpressure and emergency reliefs from Block 2000 VEBA Combi Cracker operations, controlling emissions from Block 2000 depressurization system, with pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(B) One (1) natural gas and process fuel gas-fired flare, identified as Low Pressure (LP) Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 7000 Hydrogen Unit operations, controlling emissions Block 7000 start-up and shut-down vents, and a continuous sweep stream from the Block 2000 slop tank, with a sweep and pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(C) One (1) natural gas and process fuel gas-fired flare, identified as Sulfur Block Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 3000 Sulfur Recovery operations and sulfur loading, controlling emergency streams from Sulfur Recovery Units A and B, and a continuous sweep stream from the sour water storage tanks, with a sweep and pilot heat input capacity of 0.77 MMBtu/hr (LHV), exhausting to the atmosphere.

(D) One (1) natural gas and process fuel gas-fired flare, identified as Loading Flare, approved in 2018 for construction, servicing Block 4000 naphtha, diesel, and ammonia loading operations, with a pilot heat input capacity of 0.20 MMBtu/hr (LHV), exhausting to the atmosphere.

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)
T1	IFR	Naphtha product	4,629,879 (17,524)
T2	IFR	Naphtha product	4,629,879 (17,524)
T3	FR	Diesel product	4,525,796 (17,130)
T4	FR	Diesel product	4,525,796 (17,130)
T5	FR	Diesel product	4,525,796 (17,130)
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)
T10	FR	Residue surge tank 1	926,980 (17,524)
T11	FR	Residue surge tank 2	926,980 (3,509)
T12	FR	Residue feed tank	926,980 (3,509)
T13	FR	VGO tank 1	926,980 (3,509)
T14	FR	VGO tank 2	926,980 (3,509)
T16	FR	Slop tank	4,195,581 (15,880)
T18	FR	Non-phenolic sour water storage tank 1	1,268,026 (4,799)
T19	FR	Non-phenolic sour water storage tank 2	1,268,026 (4,799)
T20	FR	Non-phenolic sour water storage tank 3	1,268,026 (4,799)
T21	FR	Phenolic sour water storage tank	40,947 (155)
T22	FR	Stripped non-phenolic sour water surge tank	1,268,026 (4,799)
T23	FR	Stripped phenolic sour water surge tank	13,737 (52)

Notes:
1. FR - fixed roof, IFR - internal floating roof

(3) Loading operations, as follows:

(A) One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

- Hydrogen unit operations, identified as Block 7000, as follows:

(1) Hydrogen Plant 1, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

(B) One (1) feed preparation train, identified as Feed Prep 1, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7001, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 1, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

(2) Hydrogen Plant 2, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

(B) One (1) feed preparation train, identified as Feed Prep 2, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7002, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 2, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

- Wastewater treatment operations, identified as Block 8000, as follows:

  (1) One (1) wastewater junction box with associated process drains, identified as Oily Water Sump, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8002.

  (2) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Water Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and water to MH1.

  (3) One (1) wastewater junction box with, identified as MH1, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8003.

  (4) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Amine Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and amine solution to the Rich Amine Return Header.

  (5) One (1) biological wastewater treatment system, approved in 2018 for construction, with emissions exhausting to vent EU-8001.

The units are subject to the following portions of Subpart CC:

(1) 40 CFR 63.640(a)
(2) 40 CFR 63.640(c)
(3) 40 CFR 63.640(d)
(4) 40 CFR 63.640(e)
(5) 40 CFR 63.640(f)
(6) 40 CFR 63.640(h)
(7) 40 CFR 63.640(k)
(8) 40 CFR 63.640(m)
(9) 40 CFR 63.640(n)(2)
(10) 40 CFR 63.640(n)(8)
(11) 40 CFR 63.640(o)(1)
(12) 40 CFR 63.640(p)(2)
(13) 40 CFR 63.641
(14) 40 CFR 63.642
(15) 40 CFR 63.643
(16) 40 CFR 63.644
(17) 40 CFR 63.645
(18) 40 CFR 63.647
(19) 40 CFR 63.654
(20) 40 CFR 63.655
(21) 40 CFR 63.656
(22) 40 CFR 63.658
(23) 40 CFR 63.670
(24) 40 CFR 63.671
(24) Table 11 to Subpart CC of Part 63

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the units except as otherwise specified in 40 CFR 63, Subpart CC.

(l) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) From Oil and Natural Gas Production Facilities, 40 CFR 63, Subpart HH and 326 IAC 20-30 are not included in the permit for this source, since the source does not process, upgrade, or store natural gas and does not process, upgrade, or store hydrocarbon liquids as defined at 40 CFR 63.761. The liquids processed and stored at the source are not naturally occurring, unrefined petroleum liquids.

(m) The requirements of the National Emission Standards for Tanks—Level 1, 40 CFR 63, Subpart OO and 326 IAC 20-35 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(n) The requirements of the National Emission Standards for Containers, 40 CFR 63, Subpart PP and 326 IAC 20-36 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(o) The requirements of the National Emission Standards for Surface Impoundments, 40 CFR 63, Subpart QQ and 326 IAC 20-37 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(p) The requirements of the National Emission Standards for Individual Drain Systems, 40 CFR 63, Subpart RR and 326 IAC 20-38 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(q) The requirements of the National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process, 40 CFR 63, Subpart SS and 326 IAC 20-39 are not included in the permit for this source. Pursuant to 40 CFR 63.640(n)(2), Group 1 storage vessels subject to 40 CFR 63, Subpart CC that are also subject to 40 CFR 60, Subpart Kb are required to comply with either 40 CFR part 60, subpart Kb, except as provided in 40 CFR 63.640(n)(8) or with 40 CFR 63, Subpart CC. This source will comply with 40 CFR 60, Subpart Kb, therefore the source is not subject to provisions of 40 CFR 63, Subpart CC that reference this subpart.

(r) The requirements of the National Emission Standards for Equipment Leaks - Control Level 1, 40 CFR 63, Subpart TT and 326 IAC 20-40 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(s) The requirements of the National Emission Standards for Equipment Leaks - Control Level 2 Standards, 40 CFR 63, Subpart UU and 326 IAC 20-41 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(t) The requirements of the National Emission Standards for Oil-Water Separators and Organic-Water Separators, 40 CFR 63, Subpart VV and 326 IAC 20-42 are not included in the permit for this source, since the source is not subject to another subpart of parts 60, 61, or 63 that references this subpart.

(u) This source is subject to the National Emission Standards for Storage Vessels (Tanks) - Control Level 2, 40 CFR 63, Subpart WW and 326 IAC 20-43, because the source is subject to Subpart CC, which references this subpart. The units subject to this rule include the following:

- Offsites operations, identified as Block 4000, consisting of:

  (2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)

ID	Construction[1]	Contents	Capacity (gallons) (m^3)
T3	FR	Diesel product	4,525,796 (17,130)
T4	FR	Diesel product	4,525,796 (17,130)
T5	FR	Diesel product	4,525,796 (17,130)
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)
T10	FR	Residue surge tank 1	926,980 (17,524)
T11	FR	Residue surge tank 2	926,980 (3,509)
T12	FR	Residue feed tank	926,980 (3,509)
T13	FR	VGO tank 1	926,980 (3,509)
T14	FR	VGO tank 2	926,980 (3,509)

These units are subject to the following portions of Subpart WW:

(1) 40 CFR 63.1060
(2) 40 CFR 63.1061
(3) 40 CFR 63.1065(a)
(4) 40 CFR 63.1067

Note: Tank T6 is subject to these requirements of Subpart WW when containing diesel fuel. When containing naphtha, tank T6 is subject to 40 CFR 60, subpart Kb and is not subject to provisions of 40 CFR 63, Subpart CC that reference this Subpart WW.

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, do not apply to this subpart except as specified in a referencing subpart.

(v) The requirements of the National Emission Standards for Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations, 40 CFR 63, Subpart XX are not included in the permit for this source, since the source does not operate an ethylene production unit or an ethylene production facility referenced to this subpart by subpart YY.

(w) The requirements of the National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards, 40 CFR 63, Subpart YY and 326 IAC 20-44 are not included in the permit for this source, since the source does not operate an ethylene production unit as defined at 40 CFR 63.1103(e)(2).

(x) This source is subject to the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, 40 CFR 63, Subpart UUU and 326 IAC 20-50, because the source is a petroleum refinery located at a major source of HAP emissions.

Pursuant to 40 CFR 63.1561(a)(1), a petroleum refinery is an establishment engaged primarily in petroleum refining as defined in the Standard Industrial Classification (SIC) code 2911 and the North American Industry Classification (NAIC) code 32411, and used mainly for::

(i) Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants;

(ii) Separating petroleum; or

(iii) Separating, cracking, reacting, or reforming an intermediate petroleum stream, or recovering a by-product(s) from the intermediate petroleum stream (e.g., sulfur recovery).

The source self-selected an SIC code other than 2911. IDEM considers that the source conforms to all three of the uses specified in paragraphs (i) through (iii) of 40 CFR 63.1561(a)(1). The definition of SIC code 2911, petroleum refining, from the 1987 SIC Manual is: "Establishments primarily engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, and lubricants, through fractionation or straight distillation of crude oil, redistillation of unfinished petroleum derivatives, cracking or other processes." IDEM recognizes that the source will not distill crude oil, if the term is limited to naturally occurring crude oil extracted from wells. However, the application of "cracking" in the SIC code definition is not qualified with modifying phrases like "of crude oil" or "of unfinished petroleum derivatives." It follows then that vacuum distillation of the liquid phase hydrocracking reactor product is redistillation of unfinished petroleum derivatives because the liquid supplied to the LPH reactor is recycled vacuum gas oil from the fractionator tower. The fractionation tower is itself a redistillation operation because the feed to gas phase hydrotreating reactor consists of unfinished petroleum derivatives that are hydrocracked in the LPH process.

The process vents and bypass lines serving the liquid phase hydrocracking (LPH) operation, gas phase hydrotreating (GPH) operation, and hydrogen production plant are not affected facilities under this subpart. These operations are not fluidized catalytic crack units, catalytic reforming units, or sulfur recovery units as defined at 40 CFR 63.1579. These operations are not described by the following definitions from 40 CFR 63.1579:

> *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 regenerated by burning off coke and other deposits.
>
> *Catalytic reforming unit* means a refinery process unit that reforms or changes the chemical structure of naphtha into higher octane aromatics through the use of a metal catalyst and chemical reactions that include dehydrogenation, isomerization, and hydrogenolysis.
>
> *Sulfur recovery unit* means a process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

The units subject to this rule include the following:

- VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

  (17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

    (A) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

    (B) One (1) two-stage low pressure absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

- Sulfur recovery operations, identified as Block 3000, consisting of:

  (1) Amine Regeneration Unit, consisting of:

    (A) One (1) heat exchanger, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

    (B) One (1) stripper column , identified as Stripper, approved in 2018 for construction, discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger and the reboiler and vapor to the overheads condenser, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

    (C) One (1) water-cooled condenser, identified as Overheads Condenser, approved in 2018 for construction, discharging condensate to the stripper condenser accumulator, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

    (D) One (1) accumulator drum, identified as Stripper Condenser Accumulator, approved in 2018 for construction, discharging condensate to stripper reflux and the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

    (E) One (1) steam-heated reboiler, identified as Stripper Reboiler, approved in 2018 for construction, discharging lean amine to the stripper reflux, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

  (2) Sour Water Stripping System, consisting of:

    (A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

    (B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

  (3) Sulfur Recovery System, consisting of:

    (A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

- (i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
- (ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.
- (iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
- (iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the TGTU A Heat Exchanger and molten sulfur to the sulfur product pit.
- (v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
- (vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
- (vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
- (viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
- (ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
- (x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
- (xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

- (i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
- (ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.
- (iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
- (iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.

(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.

(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.

(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.

(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.

(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.

(x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

This source is subject to the following portions of Subpart UUU:

(1) 40 CFR 63.1560
(2) 40 CFR 63.1561
(3) 40 CFR 63.1562(a)
(4) 40 CFR 63.1562(b)(3)
(5) 40 CFR 63.1562(b)(4)
(6) 40 CFR 63.1562(c)
(7) 40 CFR 63.1563(a)(2)
(8) 40 CFR 63.1563(d)
(9) 40 CFR 63.1563(f)
(10) 40 CFR 63.1568(a)(1)
(11) 40 CFR 63.1568(a)(2)
(12) 40 CFR 63.1568(a)(3)
(13 40 CFR 36.1568(a)(4)(i)
(14) 40 CFR 63.1568(b)
(15) 40 CFR 63.1568(c)
(16) 40 CFR 63.1569
(17) 40 CFR 63.1570
(18) 40 CFR 63.1571
(19) 40 CFR 63.1572
(20) 40 CFR 63.1573
(21) 40 CFR 63.1574
(22) 40 CFR 63.1575
(23) 40 CFR 63.1576
(24) 40 CFR 63.1577
(25) 40 CFR 63.1578
(26) 40 CFR 63.1579
(27) Table 29 to Subpart UUU of Part 63 (item 1)
(28) Table 30 to Subpart UUU of Part 63 (item 1)
(29) Table 31 to Subpart UUU of Part 63 (item 1)
(30) Table 33 to Subpart UUU of Part 63 (item 1)
(31) Table 34 to Subpart UUU of Part 63 (item 1)
(32) Table 35 to Subpart UUU of Part 63 (item 1)
(33) Table 36 to Subpart UUU of Part 63

(34) Table 37 to Subpart UUU of Part 63
(35) Table 38 to Subpart UUU of Part 63
(36) Table 39 to Subpart UUU of Part 63
(37) Table 40 to Subpart UUU of Part 63 (item 5)
(38) Table 41 to Subpart UUU of Part 63
(39) Table 42 to Subpart UUU of Part 63
(40) Table 43 to Subpart UUU of Part 63
(41) Table 44 to Subpart UUU of Part 63

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the units except as otherwise specified in 40 CFR 63, Subpart UUU.

(y) The requirements of the National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline), 40 CFR 63, Subpart EEEE and 326 IAC 20-83, are not included in the permit for this source, because, pursuant to 40 CFR 63.2338(c)(1), the storage tanks and product loading racks subject to this subpart are part of an affected source under 40 CFR 63, Subpart CC.

(z) The emergency generator and emergency fire pump are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ and 326 IAC 20-82, because the units are stationary reciprocating internal combustion engines constructed after December 19, 2002. The units subject to this rule include the following:

- One (1) diesel engine-driven emergency generator, identified as EU-6006, approved in 2018 for construction, with a maximum heat input capacity of 19.60 MMBtu/hr (2,800 hp) (average heating value), using no add-on controls and exhausting to stack EU-6006.

- One (1) diesel engine-driven emergency fire pump, identified as EU-6008, approved in 2018 for construction, with a maximum heat input capacity of 5.25 MMBtu/hr (750 hp) (average heating value), using no add-on controls and exhausting to stack EU-6008.

Based on this evaluation, this source is subject to 40 CFR 63, Subpart ZZZZ. On May 4, 2016, the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating paragraphs 40 CFR 63.6640(f)(2)(ii) - (iii) of NESHAP Subpart ZZZZ. Therefore, these paragraphs no longer have any legal effect and any engine that is operated for purposes specified in these paragraphs becomes a non-emergency engine and must comply with all applicable requirements for a non-emergency engine.

For additional information, please refer to the USEPA's Guidance Memo:
https://www.epa.gov/sites/production/files/2016-06/documents/ricevacaturguidance041516.pdf

Since the federal rule has not been updated to remove these vacated requirements, the text below shows the vacated language as ~~strikethrough~~ text. At this time, IDEM is not making any changes to the permit's attachment due to this vacatur. However, the permit will not reference the vacated requirements, as applicable.

40 CFR 63.6640(f)(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraph~~s~~ (f)(2)(i) ~~through (iii)~~ of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

~~(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.~~

~~(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.~~

EU-6006 and EU-6008 are subject to the following portions of Subpart ZZZZ:

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(a)(2)(i)
(4) 40 CFR 63.6590(b)(1)(i)
(5) 40 CFR 63.6640(f)(1)
(6) 40 CFR 63.6640(f)(2)(i)
(7) 40 CFR 63.6640(f)(3)
(8) 40 CFR 63.6645(f)
(9) 40 CFR 63.6665
(10) 40 CFR 63.6670
(11) 40 CFR 63.6675
(12) Table 8 to Subpart ZZZZ of Part 63

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to EU-6006 and EU-6008 except as otherwise specified in 40 CFR 63, Subpart ZZZZ.

(aa) This source is subject to the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD and 326 IAC 20-95, because the source owns or operates industrial, commercial, or institutional boilers or process heaters as defined in §63.7575 that are located at, or are part of, a major source of HAP.

The components of Sulfur Recovery Units A and B listed below are not boilers as defined at 40 CFR 63.7575. The units do not have a primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from the definition of "boiler" at 40 CFR 63.7575. The components of Sulfur Recovery Units A and B are not process heaters as defined at 40 CFR 63.7575. The units do not transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Except for the waste heat boilers, the units either heat process materials directly or are reactors that use or release thermal energy.

- One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

    (i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.

  - (ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.
  - (iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
  - (iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the TGTU A heat exchanger and molten sulfur to the sulfur product pit.
  - (vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
  - (x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
  - (xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

- One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, discharging emergency and pressure relief streams to the Block 4000 sulfur flare.

  - (i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
  - (ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.
  - (iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
  - (iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.
  - (vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.
  - (x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
  - (xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

The components of Hydrogen Plants 1 and 2 listed below are not boilers as defined at 40 CFR 63.7575. The units do not have a primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from the definition of "boiler" at 40 CFR 63.7575. The components of Hydrogen Plants 1 and 2 are not process heaters as defined at 40 CFR 63.7575. The units do not transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Except for the waste heat boilers, the units either heat process materials directly or are reactors that use or release thermal energy.

- Hydrogen Plant 1, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

(B) One (1) feed preparation train, identified as Feed Prep 1, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7001, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 1, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

- Hydrogen Plant 2, with a maximum capacity of 557.4 tons of hydrogen per day, consisting of:

(B) One (1) feed preparation train, identified as Feed Prep 2, approved in 2018 for construction, consisting of

(i) One (1) hydrogenation reactor.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7002, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 2, approved in 2018 for construction, using no controls and discharging shift gas to the pressure swing adsorber.

The units subject to this rule include the following:

- One (1) natural gas and process fuel gas-fired heater, identified as Coal Dryer Heater EU-1007, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 55.8 MMBtu/hr (HHV), with emissions exhausting to Stack EU-1007.

- One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2018 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

- One (1) natural gas and process fuel gas-fired indirect treat gas heater, identified as EU-2002, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 52.8 MMBtu/hr (HHV), receiving hydrogen from Block 7000 and discharging to the 1st stage reactors, exhausting to stack EU-2002.

- One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the vacuum distillation tower, exhausting to stack EU-2003.

- One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

- One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 68.50 MMBtu/hr (HHV), exhausting to stack EU-6000.

This source is subject to the following portions of Subpart DDDDD:

(1) 40 CFR 63.7480
(2) 40 CFR 63.7485
(3) 40 CFR 63.7490(a)(2)
(4) 40 CFR 63.7490(b)
(5) 40 CFR 63.7495(a)
(6) 40 CFR 63.7495(d)
(7) 40 CFR 63.7495(i)
(8) 40 CFR 63.7499(l)
(9) 40 CFR 63.7500(a)(1)
(10) 40 CFR 63.7500(a)(3)
(11) 40 CFR 63.7500(b)
(12) 40 CFR 63.7500(e)
(13) 40 CFR 63.7500(f)
(14) 40 CFR 63.7505(a)
(15) 40 CFR 63.7510(g)
(16) 40 CFR 63.7510(k)
(17) 40 CFR 63.7515(d)
(18) 40 CFR 63.7515(g)
(19) 40 CFR 63.7521(f)(1)
(20) 40 CFR 63.7530(f)
(21) 40 CFR 63.7540(a)(10)
(22) 40 CFR 63.7540(a)(11)
(23) 40 CFR 63.7540(a)(12)
(24) 40 CFR 63.7540(a)(13)
(25) 40 CFR 63.7540(b)
(26) 40 CFR 63.7540(d)
(27) 40 CFR 63.7545(a)
(28) 40 CFR 63.7545(c)
(29) 40 CFR 63.7545(e)
(30) 40 CFR 63.7545(h)
(31) 40 CFR 63.7550(a)
(32) 40 CFR 63.7550(b)
(33) 40 CFR 63.7550(c)(1)
(34) 40 CFR 63.7550(h)(3)
(35) 40 CFR 63.7555(a)

(36) 40 CFR 63.7555(h)
(37) 40 CFR 63.7560
(38) 40 CFR 63.7565
(39) 40 CFR 63.7570
(40) 40 CFR 63.7575
(41) Table 3 to Subpart DDDDD of Part 63 (item 1 (contin oxy trim), 2 (no trim, vac col feed) 3 (no trim all others))
(42) Table 9 to Subpart DDDDD of Part 63
(43) Table 10 to Subpart DDDDD of Part 63

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the units except as otherwise specified in 40 CFR 63, Subpart DDDDD.

(bb) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities, 40 CFR 63, Subpart BBBBBB are not included in the permit for this source, since because the source is a major source of HAP emissions

(cc) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63, Subpart JJJJJJ are not included in the permit for this source, since because the source is a major source of HAP emissions

(dd) There are no other National Emission Standards for Hazardous Air Pollutants Under the NESHAP, 40 CFR 63, 326 IAC 14 and 326 IAC 20 included for this proposed new source.

Compliance Assurance Monitoring (CAM):

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each new pollutant-specific emission unit that meets the following criteria:

(1) has a potential to emit before controls equal to or greater than the Part 70 major source threshold for the pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant (or a surrogate thereof); and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

(b) Pursuant to 40 CFR 64.2(b)(1)(i), emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act are exempt from the requirements of CAM. Therefore, an evaluation was not conducted for any emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act.

(c) Pursuant to 40 CFR 64.3(d), if a continuous emission monitoring system (CEMS) is required pursuant to other federal or state authority, the owner or operator shall use the CEMS to satisfy the requirements of CAM according to the criteria contained in 40 CFR 64.3(d).

The following table is used to identify the applicability of CAM to each emission unit and each emission limitation or standard for a specified pollutant based on the criteria specified under 40 CFR 64.2:

Emission Unit/Pollutant	Control Device	Applicable Emission Limitation	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
Railcar unloading (EU-1000)/PM	BH	326 IAC 2-2	<100	<100	N [1]	N

Emission Unit/Pollutant	Control Device	Applicable Emission Limitation	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
Railcar unloading (EU-1000)/PM_{10}	BH	326 IAC 2-2	<100	<100	N [2]	N
Railcar unloading (EU-1000)/$PM_{2.5}$	BH	326 IAC 2-2	<100	<100	N [3]	N
Railcar unloading (EU-1000)/single HAP	BH	none	<10	<10	N [4]	N
Railcar unloading (EU-1000)/combined HAPs	BH	none	<25	<25	N [5]	N
Coal unloading transfer (EU-1001)/PM	BH	326 IAC 2-2	<100	<100	N [1]	N
Coal unloading transfer (EU-1001)/PM_{10}	BH	326 IAC 2-2	<100	<100	N [2]	N
Coal unloading transfer (EU-1001)/$PM_{2.5}$	BH	326 IAC 2-2	<100	<100	N [3]	N
Coal unloading transfer (EU-1001)/single HAP	BH	none	<10	<10	N [4]	N
Coal unloading transfer (EU-1001)/combined HAPs	BH	none	<25	<25	N [5]	N
Coal storage (EU-1006)/PM	BH	326 IAC 2-2	<100	<100	N [1]	N
Coal storage (EU-1006)/PM_{10}	BH	326 IAC 2-2	<100	<100	N [2]	N
Coal storage (EU-1006)/$PM_{2.5}$	BH	326 IAC 2-2	<100	<100	N [3]	N
Coal storage (EU-1006)/single HAP	BH	none	<10	<10	N [4]	N
Coal storage (EU-1006)/combined HAPs	BH	none	<25	<25	N [5]	N
Coal dryer loop (EU-1008)/PM	BH	326 IAC 2-2	>100	<100	N [1]	N
Coal dryer loop (EU-1008)/PM_{10}	BH	326 IAC 2-2	>100	<100	Y	N
Coal dryer loop (EU-1008)/$PM_{2.5}$	BH	326 IAC 2-2	>100	<100	Y	N
Coal dryer loop (EU-1008)/single HAP	BH	none	<10	<10	N [4]	N
Coal dryer loop (EU-1008)/combined HAPs	BH	none	<25	<25	N [5]	N
additive & Na_2S silo loading (EU-1501-1503)/PM (each of 3)	BH	326 IAC 2-2	<100	<100	N [1]	N
additive & Na_2S silo loading (EU-1501-1503)/PM_{10} (each of 3)	BH	326 IAC 2-2	<100	<100	N [2]	N
additive & Na_2S silo loading (EU-1501-1503)/$PM_{2.5}$ (each of 3)	BH	326 IAC 2-2	<100	<100	N [3]	N
additive & Na_2S silo loading (EU-1501-1503)/single HAP (each of 3)	BH	none	<10	<10	N [4]	N
additive & Na_2S silo loading (EU-1501-1503)/combined HAPs (each of 3)	BH	none	<25	<25	N [5]	N
Fine additive production (EU-1504)/PM	BH	326 IAC 2-2	>100	<100	N [1]	N
Fine additive production (EU-1504)/PM_{10}	BH	326 IAC 2-2	>100	<100	Y	N
Fine additive production (EU-1504)/$PM_{2.5}$	BH	326 IAC 2-2	>100	<100	Y	N
Fine additive production (EU-1504)/single HAP	BH	none	<10	<10	N [4]	N

Emission Unit/Pollutant	Control Device	Applicable Emission Limitation	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
Fine additive production (EU-1504)/combined HAPs	BH	none	<25	<25	N [5]	N
Pulverized coal conveying (EU-2005)/PM	BH	326 IAC 2-2	>100	<100	N [1]	N
Pulverized coal conveying (EU-2005)/PM_{10}	BH	326 IAC 2-2	>100	<100	Y	N
Pulverized coal conveying (EU-2005)/$PM_{2.5}$	BH	326 IAC 2-2	>100	<100	Y	N
Pulverized coal conveying (EU-2005)/single HAP	BH	none	<10	<10	N [4]	N
Pulverized coal conveying (EU-2005)/combined HAPs	BH	none	<25	<25	N [5]	N
additive transfer (EU-2006-2008)/PM (each of 3)	BH	326 IAC 2-2	<100	<100	N [1]	N
additive transfer (EU-2006-2008)/PM_{10} (each of 3)	BH	326 IAC 2-2	<100	<100	N [2]	N
additive transfer (EU-2006-2008)/$PM_{2.5}$ (each of 3)	BH	326 IAC 2-2	<100	<100	N [3]	N
additive transfer (EU-2006-2008)/single HAP (each of 3)	BH	none	<10	<10	N [4]	N
additive transfer (EU-2006-2008)/combined HAPs (each of 3)	BH	none	<25	<25	N [5]	N
Sulfur recovery plant (EU-3001-3002)/SO_2 (total of 2 units)	TGTU	326 IAC 2-2	>100	<100	N [6]	N
Sulfur recovery plant (EU-3001-3002)/single HAP (total of 2 units)	TGTU	none	<10	<10	N [4]	N
Sulfur recovery plant (EU-3001-3002)/combined HAPs (total of 2 units)	TGTU	none	<25	<25	N [5]	N
Product loading rack/VOC	Flare	326 IAC 2-2	>100	<100	Y	N
Product loading rack/single HAP	Flare	none	>10	>10	N [4]	N
Product loading rack/combined HAPs	Flare	none	<25	<25	N [5]	N
Slop tank (T16)/VOC	Flare	326 IAC 2-2	<100	<100	N [7]	N
Slop tank (T16)/single HAP	Flare	none	<10	<10	N [4]	N
Slop tank (T16)/combined HAP	Flare	none	<25	<25	N [5]	N
Sour water tanks (T18-T21)/VOC	Flare	326 IAC 2-2	<100	<100	N [7]	N
Sour water tanks (T18-T21)/single HAP	Flare	none	<10	<10	N [4]	N
Sour water tanks (T18-T21)/combined HAP	Flare	none	<25	<25	N [5]	N
Residue silo loading (EU-5009-5011)/PM (each of 3)	BH	326 IAC 2-2	<100	<100	N [1]	N
Residue silo loading (EU-5009-5011)/PM_{10} (each of 3)	BH	326 IAC 2-2	<100	<100	N [2]	N

Emission Unit/Pollutant	Control Device	Applicable Emission Limitation	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
Residue silo loading (EU-5009-5011)/$PM_{2.5}$ (each of 3)	BH	326 IAC 2-2	<100	<100	N [3]	N
Residue silo loading (EU-5009-5011)/single HAP (each of 3)	BH	none	<10	<10	N [4]	N
Residue silo loading (EU-5009-5011)/combined HAPs (each of 3)	BH	none	<25	<25	N [5]	N
Cooling tower (EU-6001-6003)/PM (each of 3 cells)	DE	326 IAC 2-2	<100	<100	N [1]	N
Cooling tower (EU-6001-6003)/PM_{10} (each of 3 cells)	DE	326 IAC 2-2	<100	<100	N [2]	N
Cooling tower (EU-6001-6003)/$PM_{2.5}$ (each of 3 cells)	DE	326 IAC 2-2	<100	<100	N [3]	N
Lime truck unloading (EU-6501)/PM	BH	326 IAC 2-2	<100	<100	N [1]	N
Lime truck unloading (EU-6501)/PM_{10}	BH	326 IAC 2-2	<100	<100	N [2]	N
Lime truck unloading (EU-6501)/$PM_{2.5}$	BH	326 IAC 2-2	<100	<100	N [3]	N
Lime truck unloading (EU-6501)/single HAP	BH	none	<10	<10	N [4]	N
Lime truck unloading (EU-6501)/combined HAPs	BH	none	<25	<25	N [5]	N
Hydrogen plant reformer (EU-7001-7002)/NOx (each of 2)	SCR	326 IAC 2-2	>100	<100	N [6]	N
Wastewater treatment/VOC	CC	326 IAC 2-2	<100	<100	N [7]	N
Wastewater treatment/single HAP	CC	none	<10	<10	N [4]	N
Wastewater treatment/combined HAPs	CC	none	<25	<25	N [5]	N

Uncontrolled PTE (tpy) and controlled PTE (tpy) are evaluated against the Major Source Threshold for each pollutant. Major Source Threshold for criteria pollutants (PM10, PM2.5, SO2, NOX, VOC and CO) is 100 tpy, for a single HAP ten (10) tpy, and for total HAPs twenty-five (25) tpy.
Under the Part 70 Permit program (40 CFR 70), PM is not a regulated pollutant.

N [1] Under 326 IAC 2-2, PM is not a surrogate for a regulated air pollutant. Therefore, CAM does not apply to these emission units for the 326 IAC 2-2 PM limitation.

N [2] CAM does not apply for PM_{10} because the uncontrolled PTE of PM_{10} is less than the major source threshold.

N [3] CAM does not apply for $PM_{2.5}$ because the uncontrolled PTE of $PM_{2.5}$ is less than the major source threshold.

N [4] CAM does not apply for any single HAP because the unit is not subject to a limitation.

N [5] CAM does not apply for combined HAPs because the unit is not subject to a limitation.

N [6] A continuous compliance determination method, which provides data either in units of the standard or correlated directly to the compliance limit, is already specified in the Part 70 permit. Therefore, the emission limitation or standard is exempt from the requirements of 40 CFR Part 64, CAM.

N [7] CAM does not apply for VOC because the uncontrolled PTE of VOC is less than the major source threshold.

Controls: BH = Baghouse, SCR=selective catalytic reduction, TGTU=Tail Gas Treatment Unit, DE=drift eliminator, CC=carbon cannister

Emission units without air pollution controls are not subject to CAM. Therefore, they are not listed.

Based on this evaluation, the requirements of 40 CFR Part 64, CAM, are applicable to the coal dryer loop (EU-1008), fine additive production system (EU-1504), and pulverized coal conveying (EU-2005), which are each not considered a "large unit," for PM_{10} and $PM_{2.5}$, and for the product loading rack, which is not considered a "large unit," for VOC upon issuance of the Part 70 Permit Renewal. A CAM plan must be submitted as part of the Part 70 Operating Permit Renewal application.

State Rule Applicability Determination

State rule applicability for this new source has been reviewed as follows:

326 IAC 2-2 (PSD)
PSD applicability is discussed under the Permit Level Determination – PSD section.

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to 326 IAC 2-2-3 (Control Technology Review Requirements), the Permittee shall comply with the following BACT limits:

(a) PM, PM_{10}, and $PM_{2.5}$ BACT for the coal handling operations shall be as follows:

(1) Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	gr/dscf	lb/hr
Railcar unloading, including: Receiving Pits 1 & 2 Receiving Bins 1 & 2 Drag Flight Feeders 1& 2 (EU-1000)	Baghouse EU-1000 (stack EU-1000) Water spray dust suppression (bins & feeders only)	PM	0.0022	0.12
		PM_{10}	0.0022	0.12
		$PM_{2.5}$	0.0022	0.12
Transfer station, including: Unloading Conveyor (EU-1001)	Baghouse EU-1001 (stack EU-1001)	PM	0.002	0.16
		PM_{10}	0.002	0.16
		$PM_{2.5}$	0.002	0.16
Coal storage enclosure 1, including Conveyor 1 Stacker 1 Boom/Chute Stockpiles #1A & #1B Reclaimer 1 Coal storage enclosure 2, including: Conveyor 2 Stacker 2 Boom/Chute Stockpiles #2A & #2B Reclaimer 2 Reclaim transfer station, including: Conveyor 6 Conveyor 7 Conveyor 9	Baghouse EU-1006 (stack EU-1006)	PM	0.002	0.11
		PM_{10}	0.002	0.11
		$PM_{2.5}$	0.002	0.11
Coal drying loop purge, including: Conveyor 8 Coal mill & pulverizer Coal Dryer	Loop Purge Baghouse (stack EU-1008)	PM	0.002	0.26
		PM_{10}	0.002	0.26

(1) Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	gr/dscf	lb/hr
		$PM_{2.5}$	0.002	0.26
Enclosed screw conveyor to Block 2000 feed premix drum	Coal Handling System Filter (stack EU-2005)	PM	0.002	0.003
		PM_{10}	0.002	0.003
		$PM_{2.5}$	0.002	0.003

PM_{10} and $PM_{2.5}$ include both filterable and condensable PM.

(2) There shall be no (0%) visible emissions from the entrance and exit doors of the unloading enclosure at any time.

(b) PM, PM_{10}, and $PM_{2.5}$ BACT for the additive handling operations shall be as follows:

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	gr/dscf	lb/hr
Coarse additive silo, T34 (EU-1501)	Baghouse EU-1501 (stack EU-1501)	PM	0.002	0.016
		PM_{10}	0.002	0.016
		$PM_{2.5}$	0.002	0.016
Fine additive silo, T33 (EU-1502)	Baghouse EU-1502 (stack EU-1502)	PM	0.002	0.018
		PM_{10}	0.002	0.018
		$PM_{2.5}$	0.002	0.018
Na_2S silo, T35 (EU-1503)	Baghouse EU-1503 (stack EU-1503)	PM	0.002	0.013
		PM_{10}	0.002	0.013
		$PM_{2.5}$	0.002	0.013
Fine additive production system	Baghouse EU-1504 (stack EU-1504)	PM	0.002	0.004
		PM_{10}	0.002	0.004
		$PM_{2.5}$	0.002	0.004
Coarse additive screw conveyor	Coarse additive system filter (stack EU-2006)	PM	0.002	0.004
		PM_{10}	0.002	0.004
		$PM_{2.5}$	0.002	0.004
Fine additive transfer system	Fine additive system filter (stack EU-2007)	PM	0.002	0.004
		PM_{10}	0.002	0.004
		$PM_{2.5}$	0.002	0.004
Na_2S slurry preparation system	Na_2S handling system filter (stack EU-2008)	PM	0.002	0.001
		PM_{10}	0.002	0.001
		$PM_{2.5}$	0.002	0.001

PM_{10} and $PM_{2.5}$ include both filterable and condensable PM.

(c) BACT for the fuel combustion units shall be as follows:

(1) PM, PM_{10}, and $PM_{2.5}$:

(A) The units shall burn only natural gas and process off-gas.

(B) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(C) Particulate matter emissions shall not exceed:

Emission Limitations			
Unit ID	**Pollutant**	**lb/MMBtu**	**lb/hr**
EU-1007	PM (filterable)	0.0019	0.11
	PM_{10}	0.0075	0.42
	$PM_{2.5}$	0.0075	0.42
EU-2001	PM (filterable)	0.0019	0.24
	PM_{10}	0.0075	0.96
	$PM_{2.5}$	0.0075	0.96
EU-2002	PM	0.0075	0.10
	PM_{10}	0.0075	0.40
	$PM_{2.5}$	0.0075	0.40
EU-2003	PM (filterable)	0.0019	1.71E-02
	PM_{10}	0.0075	6.75E-02
	$PM_{2.5}$	0.0075	6.75E-02
EU-2004	PM (filterable)	0.0019	0.30
	PM_{10}	0.0075	1.17
	$PM_{2.5}$	0.0075	1.17
EU-6000	PM (filterable)	0.0019	0.13
	PM_{10}	0.0075	0.51
	$PM_{2.5}$	0.0075	0.51

PM_{10} and $PM_{2.5}$ include both filterable and condensable PM.

(2) SO_2:

(A) The units shall burn only natural gas and process off-gas.

(B) The average sulfur content of the fuel gas combusted shall not exceed 0.005 gr/scf per twelve (12) consecutive month period with compliance determined at the end of each month.

(C) SO_2 emissions shall not exceed:

SO_2 Emission Limitations	
Unit ID	**tpy**
EU-1007	0.35
EU-2001	0.80
EU-2002	0.33
EU-2003	0.06
EU-2004	0.97
EU-6000	0.42

(3) NOx:

(A) The units shall burn only natural gas and process off-gas.

(B) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(C) The units shall use ultra-low-NOx burners.

(D) NOx emissions shall not exceed:

Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
EU-1007	0.030	1.67
EU-2001	0.030	3.85
EU-2002	0.030	1.58
EU-2003	0.030	0.27
EU-2004	0.030	4.68
EU-6000	0.030	2.06

(4) VOC:

(A) The units shall burn only natural gas and process off-gas.

(B) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(C) VOC emissions shall not exceed:

Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
EU-1007	0.0054	0.30
EU-2001	0.0054	0.69
EU-2002	0.0054	0.29
EU-2003	0.0054	0.05
EU-2004	0.0054	0.84
EU-6000	0.0054	0.37

(5) CO:

(A) The units shall burn only natural gas and process off-gas.

(B) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(C) CO emissions shall not exceed:

Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
EU-1007	0.0365	2.04
EU-2001	0.0365	4.69
EU-2002	0.0365	1.93
EU-2003	0.0365	0.33
EU-2004	0.0365	5.69
EU-6000	0.0365	2.50

(6) Carbon dioxide equivalent (CO_2e), as defined at 40 CFR 98.6:

(A) The units shall burn only natural gas and process off-gas.

(B) The units shall be designed and operated to achieve the highest practical energy efficiency.

(C) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(D) CO_2e emissions shall not exceed the value of tons per twelve (12) consecutive month period shown in the table below:

Emission Limitations	
Unit ID	**CO_2e Limit**
EU-1007	29,127
EU-2001	67,023
EU-2002	27,561
EU-2003	4,698
EU-2004	81,430
EU-6000	35,756

(d) BACT for the sulfur recovery units shall be as follows:

(1) PM (filterable) emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0019 lb/MMBtu and 0.10 lb/hr, each.

(2) PM_{10} emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0074 lb/MMBtu and 0.39 lb/hr, each.

(3) $PM_{2.5}$ emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0074 lb/MMBtu and 0.39 lb/hr, each.

(4) The SO_2 emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 150 ppmv @ 0% excess air (on a twelve month rolling average) and shall be less than 167 ppmv @ 0% excess air (on a twelve hour average).

(5) The SO_2 emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 26.30 lb/hr, each.

(6) The tail gas treatment units (TGTUA and TGTUB) shall each use low-NOx burners.

(7) NOx emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.10 lb/MMBtu and 5.28 lb/hr, each.

(8) VOC emissions from the tail gas treatment unit stacks (EU-3001 and EU-3002) shall not exceed 0.0054 lb/MMBtu and 0.28 lb/hr, each.

(9) CO emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 65 ppmv @ 0% O_2, shall not exceed 0.082 lb/MMBtu and 4.33 lb/hr, each.

(10) Sulfuric Acid Mist (H_2SO_4 mist) emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0244 lb/MMBtu and 1.29 lb/hr, each.

(11) Opacity shall not exceed ten percent (10%) on a six-minute average.

(12) Incinerators A-605A and A-605B) shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(13) Carbon dioxide equivalent (CO_2e) emissions, as defined at 40 CFR 98.6, from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 40,872 tons per twelve (12) consecutive month period, combined, with compliance determined at the end of each month.

(e) BACT for the SB, LP, and HP flares shall be as follows:

(1) The units shall burn only natural gas and process off-gas as supplemental and pilot fuel.

(2) PM, PM_{10}, and $PM_{2.5}$:

(A) Particulate matter emissions while operating in sweep and pilot mode shall not exceed:

Emission Limitations			
Unit ID	**Pollutant**	**lb/MMBtu**	**lb/hr**
HP Flare	PM FILTRABLE	0.0019	0.014
	PM_{10}	0.0074	0.053
	$PM_{2.5}$	0.0074	0.053
LP Flare	PM FILTRABLE	0.0019	0.014
	PM_{10}	0.0074	0.053
	$PM_{2.5}$	0.0074	0.053
SB Flare	PM FILTRABLE	0.0019	1.62E-03
	PM_{10}	0.0074	6.32E-03
	$PM_{2.5}$	0.0074	6.32E-03

(B) The HP Flare and LP Flare shall operate with no visible emissions, except for periods not to exceed a total of five (5) minutes during any two (2) consecutive hours when flaring a process stream.

(3) SO_2:

(A) The Permittee shall burn only natural gas and process off-gas in any flare as supplemental or pilot fuel gas.

(B) SO_2 emissions while operating in sweep and pilot mode shall not exceed:

SO_2 Emission Limitations	
Unit ID	**lb/hr**
HP Flare	0.013
LP Flare	0.013

(C) SO_2 emissions from the SB Flare shall not exceed 0.069 lb/ hr when operating in sweep and pilot mode.

(4) NOx:

(A) NOx emissions while operating in sweep and pilot mode shall not exceed:

NOx Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
HP Flare	0.099	0.71
LP Flare	0.099	0.71
SB Flare	0.099	8.46E-02

(B) NOx emissions shall not exceed 0.068 lb/MMBtu (LHV) when flaring a process stream.

(5) VOC:

(A) VOC emissions while operating in sweep and pilot mode shall not exceed:

VOC Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
HP Flare	0.0054	0.039
LP Flare	0.0054	0.039
SB Flare	0.0054	4.62E-03

(B) VOC destruction and removal efficiency shall not be less than 98% when flaring a process stream.

(6) The Best Available Control Technology (PSD BACT) for CO for the flares shall be as follows:

(A) CO emissions while operating in sweep and pilot mode shall not exceed:

CO Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
HP Flare	0.083	0.60
LP Flare	0.083	0.60
SB Flare	0.083	7.09E-02

(B) CO emissions shall not exceed 0.31 lb/MMBtu (LHV) when flaring a process stream.

(7) Carbon dioxide equivalent (CO_2e) emissions, as defined at 40 CFR 98.6, from the flares listed in the table below when operating in sweep and pilot mode shall not exceed the values shown per twelve (12) consecutive month period, with compliance determined at the end of each month.

Emission Limitations	
Unit ID	**CO_2e Limit**
Sulfur Block Flare	448
LP Flare	3,781
HP Flare	3,781

(f) BACT for the tanks shall be as follows:

(1) VOL (as defined at 40 CFR 60.111b) tanks, T1, T2, and T6, shall use internal floating roofs.
(2) Emissions from the slop tank, T16, shall be controlled by the LP Flare at all times and the slop tank throughput shall not exceed the value shown in the table below per twelve (12) consecutive month period with compliance determined at the end of each month.
(3) Emissions from the sour water tanks, T18 - T21, shall be controlled by the Sulfur Block Flare at all times and the sour water tank throughputs shall each not exceed the values shown in the table below per twelve (12) consecutive month period with compliance determined at the end of each month.
(4) All tanks shall use white tank shells.
(5) All tanks shall use submerged filling.
(6) All tanks shall use good maintenance practices based on generally-accepted industry standards, including but not limited to API 650 Welded Steel Tanks for Oil Storage and API 653 Tank Inspection, Repair, Alteration, and Reconstruction.
(7) Tanks shall comply with the following limitations:

Tank ID	Product Stored	Storage Temperature (°F)	VOC Emissions Limit (tons/yr)	Throughput Limit (kgal/yr)
T1	Naphtha Product	ambient	1.15	-
T2	Naphtha Product	ambient	1.15	-
T3	Diesel Product	ambient	2.29	-
T4	Diesel Product	ambient	2.29	-
T5	Diesel Product	ambient	2.29	-
T6	Naphtha Product	ambient	1.15	-
	Diesel Product	ambient	0.17	-
T10	Residue	505	1E-04	-
T11	Residue	505	1E-04	-
T12	Residue	505	1E-04	-
T13	VGO	505	0.175	-
T14	VGO	505	0.175	-
T16	Slop tank	ambient	-	305,467
T17	Diesel Fuel	ambient	1.14E-02	-
T18	Non-Phenolic Sour Water	ambient	-	462,829
T19	Non-Phenolic Sour Water	ambient	-	462,829
T20	Non-Phenolic Sour Water	ambient	-	462,829
T21	Phenolic Sour Water	ambient	-	4,628
T22	Stripped Non-Phenolic Sour Water	ambient	0.48	-
T23	Stripped Phenolic Sour Water	ambient	0.48	-
T24	Amine Surge/Deinventory	ambient	0.48	-

Tank ID	Product Stored	Storage Temperature (°F)	VOC Emissions Limit (tons/yr)	Throughput Limit (kgal/yr)
T25	Fresh Amine	ambient	0.48	-
T26	Amine Containment	ambient	0.48	-
EU-6005	Emergency generator diesel fuel	ambient	1.14E-02	-
EU-6008	Emergency fire pump diesel fuel	ambient	1.14E-02	-

(g) BACT for the product loading operations shall be as follows:

(1) The Loading Flare shall burn only natural gas and process off-gas as supplemental and pilot fuel.

(2) The Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the Loading Flare shall be as follows:

(A) Particulate matter emissions while operating pilot mode shall not exceed:

Emission Limitations			
Unit ID	**Pollutant**	**lb/MMBtu**	**lb/hr**
Loading Flare	$PM_{FILTRABLE}$	0.0019	4.22E-04
	PM_{10}	0.0074	1.64E-03
	$PM_{2.5}$	0.0074	1.64E-03

(3) The Best Available Control Technology (PSD BACT) for SO_2 for the Loading Flare shall be as follows:

(A) The Permittee shall burn only natural gas and process off-gas in any flare as supplemental or pilot fuel gas

(B) SO_2 emissions from the Loading Flare shall not exceed 0.069 lb/ hr when operating in pilot mode.

(4) The Best Available Control Technology (PSD BACT) for NOx for the Loading Flare shall be as follows:

(A) NOx emissions while operating in pilot mode shall not exceed:

NOx Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
Loading Flare	0.099	2.20E-02

(B) NOx emissions shall not exceed 0.068 lb/MMBtu (LHV) when controlling emissions from naphtha or diesel loading operations.

(5) The Best Available Control Technology (PSD BACT) for VOC for the Loading Flare shall be as follows:

(A) VOC emissions while operating in pilot mode shall not exceed:

VOC Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
Loading Flare	0.0054	1.20E-03

(B) The Product Loading Rack shall use only submerged loading.

(C) The overall VOC control efficiency, including capture efficiency and destruction efficiency, for the product Loading Flare shall be 98% or greater.

(D) VOC emissions shall not exceed:

Emission Limitations	
Product	**lb/kgal**[1]
naphtha	0.049
diesel	1.02E-03

1. kgal = 1,000 gallons

(6) The Best Available Control Technology (PSD BACT) for CO for the Loading Flare shall be as follows:

(A) CO emissions while operating in pilot mode shall not exceed:

CO Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
Loading Flare	0.083	1.84E-02

(B) CO emissions shall not exceed 0.31 lb/MMBtu (LHV) when flaring a process stream.

(7) Carbon dioxide equivalent (CO_2e) emissions, as defined at 40 CFR 98.6, from the Loading Flare shall not exceed 559 tons per twelve (12) consecutive month period, combined, with compliance determined at the end of each month.

(h) BACT for the residue solidification and handling operations shall be as follows:

(1) VOC emissions from residue solidification unit EU-5001a-5001d (stack EU-5001) shall not exceed 1.40 lb/hr.

(2) VOC emissions from residue solidification unit EU-5002a-5002d (stack EU-5002) shall not exceed 1.40 lb/hr.

(3) VOC emissions from residue solidification unit EU-5003a-5003d (stack EU-5003) shall not exceed 1.40 lb/hr.

(4) VOC emissions from residue solidification unit EU-5004a-5004d (stack EU-5004) shall not exceed 1.40 lb/hr.

(5) PM, PM_{10}, and $PM_{2.5}$ for the solid residue handling operations shall be as follows:

Emission Unit Description (ID)	**Control Device (Stack ID)**	**Emission Limitations**		
		Pollutant	**gr/dscf**	**lb/hr**
Residue bulk container loading and residue	Filter EU-5009 (stack EU-5009)	PM	0.002	0.001
		PM_{10}	0.002	0.001

Emission Unit Description (ID)	**Control Device (Stack ID)**	**Emission Limitations**		
		Pollutant	**gr/dscf**	**lb/hr**
transfer conveyors (EU-5009)		$PM_{2.5}$	0.002	0.001
Residue rail storage silo (EU-5010), loading hoppers (EU-5005, EU-5006), and residue transfer conveyors	Filter EU-5010 (stack EU-5010)	PM	0.002	0.003
		PM_{10}	0.002	0.003
		$PM_{2.5}$	0.002	0.003
Residue swing storage silo (EU-5011), loading hoppers (EU-5007, EU-5008), and residue transfer conveyors	Filter EU-5011 (stack EU-5011)	PM	0.002	0.003
		PM_{10}	0.002	0.003
		$PM_{2.5}$	0.002	0.003

PM_{10} and $PM_{2.5}$ include both filterable and condensable PM.

(6) Transfers from the loading hoppers to transports shall employ choke flow-practices

(7) There shall be no visible emissions from transfers from the loading hoppers and from hoppers to transports.

(i) BACT for the utilities shall be as follows:

(1) PM, PM_{10}, and $PM_{2.5}$ emissions from the cooling tower (EU-6001, EU-6002 and EU-6003) shall be controlled by the use of drift eliminators with a maximum drift rate of no more than 0.0005%.

(2) Total dissolved solids (TDS) in the circulating cooling water shall not exceed 2,395 mg/l.

(3) VOC emissions from the cooling towers (EU-6001, EU-6002 and EU-6003) shall not exceed 1.34 lb/hr.

(4) Emissions from the emergency engines shall not exceed the following:

Emission Unit	Unit ID	Pollutant	Limitation	
Emergency Diesel Generator	EU-6006	PM	0.20 g/kW-hr	Use of Tier 2 diesel engine
		PM_{10}	0.20 g/kW-hr	
		$PM_{2.5}$	0.20 g/kW-hr	
		SO_2	15 ppm in fuel	
		NOx + NMHC	6.40 g/kW-hr	
		CO	3.50 g/kW-hr	
		Opacity	Acceleration: 20% Lugging: 15% Peak: 50%	
		CO_2e	811 tons per twelve (12) consecutive month period with compliance determined at the end of each month	
Emergency Diesel Fire Pump	EU-6008	PM	0.20 g/kW-hr	Engine that complies with Table 4, 40 CFR 60, Subpart IIII
		PM_{10}	0.20 g/kW-hr	
		$PM_{2.5}$	0.20 g/kW-hr	
		SO_2	15 ppm in fuel	
		NOx + NMHC	4.00 g/kW-hr	
		CO	3.50 g/kW-hr	
		CO_2e	217 tons per twelve (12) consecutive month period with compliance determined at the end of each month	

(5) Emergency generator (EU-6006) and emergency fire pump (EU-6008) shall use good combustion practices and shall use energy efficiency.

(j) BACT for the hydrogen production units shall be as follows:

(1) The units shall burn only natural gas and process off-gas.

(2) PM, PM_{10}, and $PM_{2.5}$ emissions from each reformer shall not exceed:

Emission Limitations	
Pollutant	**lb/MMBtu**
PM	0.006
PM_{10}	0.006
$PM_{2.5}$	0.0048

PM_{10} and $PM_{2.5}$ shall include filterable and condensable PM.

(3) Sulfur content of the fuel gas delivered to each reformer shall not exceed 0.005 gr/scf.

(4) The units shall use selective catalytic reduction (SCR) with low-NOx burners for NOx control.

(5) NOx emissions from each reformer shall not exceed:

Emission Limitations	
Pollutant	**lb/MMBtu**
NOx	0.0065

(6) VOC emissions from each reformer shall not exceed:

Emission Limitations	
Pollutant	**lb/MMBtu**[1]
VOC	0.0015

(7) CO emissions from each reformer shall not exceed:

Emission Limitations	
Pollutant	**lb/MMBtu**
CO	0.020

(8) The CO_2e emissions from Block 7000 hydrogen production operations shall not exceed the values shown in the table below per twelve (12) consecutive month period, with compliance determined at the end of each month.

Emission Limitations	
Unit ID	**CO_2e Limit (tons)**
EU-7001	986,271
EU-7002	986,271
EU-7003	1,080
EU-7004	1,080

(9) VOC emissions from the hydrogen plant deaerators (EU-7003 and EU-7004) shall not exceed 3.20 lb/hr, each.

(10) CO emissions from the hydrogen plant deaerators (EU-7003 and EU-7004) shall not exceed 1.06 lb/hr, each.

(k) BACT for the water operations shall be as follows:

(1) Lime handling operations PM, PM_{10}, and $PM_{2.5}$:

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	**gr/dscf**	**lb/hr**
Lime silo (EU-6501)	Filter EU-6501 (stack EU-6501)	PM	0.002	0.01
		PM_{10}	0.002	0.01
		$PM_{2.5}$	0.002	0.01

PM_{10} and $PM_{2.5}$ include both filterable and condensable.

(2) VOC emissions from the wastewater treatment vent (EU-8001), oily water sump (EU-8002), and manhole no. 1 (EU-8003) shall not exceed 20 parts per million by volume (dry) (ppmvd), each.

(l) BACT for the refinery process fugitive emissions shall be as follows:

(1) Fugitive VOC emissions shall be controlled by a Leak Detection and Repair (LDAR) program. The leak detection and repair program specified in 40 CFR 60, Subpart GGGa shall serve as BACT for VOC fugitive emissions.

(A) Fugitive VOC emissions from Block 2000 VEBA Combi Cracker operations shall not exceed 151.18 tons per twelve (12) consecutive month period, with compliance determined monthly.

(B) Fugitive VOC emissions from Block 4000 offsites operations shall not exceed 25.04 tons per twelve (12) consecutive month period.

(m) BACT for paved roads shall be as follows:

(a) The Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the paved roads shall be the development, maintenance, and implementation of a fugitive dust control plan, which shall include but not be limited to vacuum sweeping and water flushing as necessary and the implementation of a speed reduction plan

(b) Visible emissions from truck traffic on plant roads shall not exceed one (1) minute in any one (1) hour period.

326 IAC 2-2-5 (Air Quality Impact Requirements)

(a) Pursuant to 326 IAC 2-2-5(e)(1) the Permittee shall conduct an air quality impact analysis in accordance with the following provisions:

(1) Any estimates of ambient air concentrations used in the demonstration process shall be based upon the applicable air quality models, data bases, and other requirements specified in 40 CFR Part 51, Appendix W (Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Guideline on Air Quality Models).

(2) Where an air quality impact model specified in the guidelines in subdivision (1) is inappropriate, a model may be modified or another model substituted provided that all applicable guidelines are satisfied.

(3) Modifications or substitution of any model may only be done in accordance with guideline documents and with written approval from U.S. EPA and shall be subject to the public comment procedures set forth in 326 IAC 2-1.1-6.

(b) Pursuant to 326 IAC 2-2-5 (Air Quality Impact; Requirements), the source shall comply with the following:

(1) Emergency generator (EU-6006) shall not exceed 100 hours of operation, per twelve (12) consecutive month period with compliance determined at the end of each month.

(2) Emergency fire pump (EU-6008) shall not exceed 200 hours of operation, per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) Pursuant to 326 IAC 2-2-5 (Air Quality Impact; Requirements), sulfur content of the fuel gas and SO_2 emissions of the fuel gas combustion units listed in the table below shall not exceed the following:

Unit ID	Sulfur Content (gr/scf)	SO_2 Emission Limitations (lb/hr)
EU-1007	0.0063	0.10
EU-2001	0.0065	0.24
EU-2002	0.0064	0.10
EU-2003	0.0062	0.02
EU-2004	0.0063	0.28
EU-6000	0.0063	0.12

See Appendix C to this Technical Support Document (TSD) for the PSD air quality analysis.

326 IAC 2-2-6 (Increment Consumption Requirements)
Pursuant to 326 IAC 2-2-6(a) any demonstration under 326 IAC 2-2-5 shall demonstrate that increased emissions caused by the proposed stationary source will not exceed eighty percent (80%) of the available maximum allowable increases (MAI) over the baseline concentrations of PM, PM_{10}, $PM_{2.5}$, VOC, CO, NO_x and Greenhouse Gases, indicated in 326 IAC 2-2-6(b)(1). PM, PM_{10}, $PM_{2.5}$, VOC, CO, NO_x and Greenhouse Gases are emitted and subject to PSD in this proposed permit, T147-39554-00065.

326 IAC 2-2-7 (Additional Analysis, Requirements)
Pursuant to 326 IAC 2-2-7(a) the Permittee shall conduct an analysis of the impairment to visibility, soils and vegetation. An analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the source was performed. The results of the additional impact analysis concluded the modification will have no adverse impact on economic growth, soils, vegetation, and endangered or threatened species.

See Appendix C to this Technical Support Document (TSD) for the PSD air quality analysis.

326 IAC 2-2-8 (Source Obligation)
(a) Pursuant to 326 IAC 2-2-8(1), approval to construct shall become invalid if construction is not commenced within eighteen (18) months after receipt of the approval, if construction is discontinued for a period of eighteen (18) months or more, or if construction is not completed within a reasonable time.

(b) Approval for construction shall not relieve the Permittee of the responsibility to comply fully with applicable provisions of the state implementation plan and any other requirements under local, state, or federal law.

326 IAC 2-2-9 (Innovative Control Technology)
Pursuant to 326 IAC 2-2-9 the Permittee may request the commissioner in writing to approve a system of innovative control technologies as part of the PSD application for T147-39554-00065.

326 IAC 2-2-10 (Source Information)
Pursuant to 326 IAC 2-1-10, the Permittee has submitted all information necessary to perform an analysis or make the determination required under 326 IAC 2-2.

326 IAC 2-2-12 (Permit Rescission)
Pursuant to 326 IAC 2-2-12, the permit issued under 326 IAC 2-2 shall remain in effect unless and until it is rescinded, modified, revoked, or it expires in accordance with 326 IAC 2-1.1-9.5 or 326 IAC 2-2-8.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
(a) The operation of the units listed in the table below will each emit equal to or greater than ten (10) tons per year for a single HAP and equal to or greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 would apply to units. However, pursuant to 326 IAC 2-4.1-1(b)(2), because these units are specifically regulated by NESHAP 40 CFR 63, Subpart CC, which was issued pursuant to Section 112(d), 112(h), or 112(j) of the Clean Air Act, the units are exempt from the requirements of 326 IAC 2-4.1.

Unit
Product Loading Rack
Hydrogen Plant Deaeration Vents
VCC fugitive emissions

(b) The operation of all other facilities at the source will each emit less than ten (10) tons per year for a single HAP and less than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply to other facilities at the source.

326 IAC 2-6 (Emission Reporting)

This source is subject to 326 IAC 2-6 (Emission Reporting) because it is required to have an operating permit pursuant to 326 IAC 2-7 (Part 70). The potential to emit of VOC is greater than 250 tons per year. Therefore, pursuant to 326 IAC 2-6-3(a)(1), annual reporting is required. An emission statement shall be submitted in accordance with the compliance schedule in 326 IAC 2-6-3 and every year thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 2-7-6(5) (Annual Compliance Certification)

The U.S. EPA Federal Register 79 FR 54978 notice does not exempt Title V Permittees from the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D), but the submittal of the Title V annual compliance certification to IDEM satisfies the requirement to submit the Title V annual compliance certifications to EPA. IDEM does not intend to revise any permits since the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D) still apply, but Permittees can note on their Title V annual compliance certifications that submission to IDEM has satisfied reporting to EPA per Federal Register 79 FR 54978. This only applies to Title V Permittees and Title V compliance certifications.

326 IAC 3-5 (Continuous Monitoring of Emissions)

(a) Pursuant to 326 IAC 3-5-1(a), 326 IAC 3-5 applies to the emissions units listed in the table below, which are required to perform continuous monitoring under 326 IAC 12, incorporating 40 CFR 60 by reference.

Unit	ID	Applicable NSPS
Coal dryer heater	EU-1007	40 CFR 60, Subpart Ja
Feed heater	EU-2001	40 CFR 60, Subpart Ja
Treat gas heater	EU-2002	40 CFR 60, Subpart Ja
Fractionator heater	EU-2004	40 CFR 60, Subparts Db and Ja
TGTU A	EU-3001	40 CFR 60, Subpart Ja
TGTU B	EU-3002	40 CFR 60, Subpart Ja
Boiler	EU-6000	40 CFR 60, Subpart Ja

(b) Pursuant to 326 IAC 3-5-1(d), IDEM requires, as a condition of a construction or operating permit issued under 326 IAC 2-2 and 326 IAC 2-7 that the source monitor emissions of the units listed in the table below to ensure compliance with an emission limitation or standard established in one (1) of the permits listed in 326 IAC 3-5-1(d).

Unit	ID
Reformer furnace 1	EU-7001
Reformer furnace 2	EU-7002

(c) Pursuant to 326 IAC 3-5-1(b) and (d), emissions units described in (a) and (b) are subject to the following requirements:

(1) Any emissions unit subject to 326 IAC 12, shall comply with the monitoring and reporting requirements as specified for the applicable rule.

(2) All requirements of 326 IAC 3-5.

326 IAC 5-1 (Opacity Limitations)

This source is subject to the opacity limitations specified in 326 IAC 5-1-2(1).

326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating)

Pursuant to 326 IAC 6-2-1(h), the units listed in the table below are not subject to the requirements of 326 IAC 6-2, since the limitations established in 326 IAC 6-2 are inconsistent with limitations required by 326 IAC 2. The operations are subject to prevention of significant deterioration (PSD) best available control technology (BACT) requirements under 326 IAC 2-2-3.

Unit	ID
Coal dryer heater	EU-1007
Feed heater	EU-2001
Treat gas heater	EU-2002
Vacuum column feed heater	EU-2003
Fractionator heater	EU-2004
Boiler	EU-6000

326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)

Pursuant to 326 IAC 6-3-1(c)(1), the units listed in the table below are not subject to the requirements of 326 IAC 6-3, since the operations are subject to particulate matter limitations that are as stringent as or more stringent than the particulate emission limitations established in 326 IAC 6-3. The operations are subject to prevention of significant deterioration (PSD) best available control technology (BACT) requirements under 326 IAC 2-2-3.

Process Unit
Block 1000
Block 1500
Block 2000
Block 3000
Block 4000
Block 5000
Block 6000
Block 6500
Block 7000
Block 8000

326 IAC 6-4 (Fugitive Dust Emissions)

The source is subject to the requirements of 326 IAC 6-4, because vehicle traffic on paved and unpaved roads has the potential to emit fugitive particulate emissions. Pursuant to 326 IAC 6-4 (Fugitive Dust Emissions Limitations), the source 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.

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)

The source is not subject to the requirements of 326 IAC 6-5, because vehicle traffic on paved and unpaved roads does not have potential fugitive particulate emissions greater than 25 tons per year.

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)

The sulfur recovery units, SRU A and SRU B, are subject to 326 IAC 326 IAC 7-1.1 because the SO_2 PTE of each unit is equal to or greater than 25 tons/year or 10 pounds/hour.

(a) The sulfure dioxide emission limitations in 326 IAC 7-1.1-2 are not applicable to SRU A and SRU B because the units are not fuel combustion units.

(b) The compliance test methods in 326 IAC 7-2 are not applicable to SRU A and SRU B because the units are not subject to limitations in 326 IAC 7-1.1, 326 IAC 7-4, or 326 IAC 7-4.1.

(c) Pursuant to 326 IAC 7-1.1-1(3), SRU A ans SRU B shall comply with sulfur dioxide emission limitations and other requirements under 326 IAC 2 and 326 IAC 12.

326 IAC 8-1-6 (New Facilities: General Reduction Requirements)

(a) Each new unit listed in the table below is not subject to the requirements of 326 IAC 8-1-6, since the unlimited VOC potential emissions from each new unit is less than twenty-five (25) tons per year.

Description	Unit ID	Description	Unit ID
Coal unloading	EU-1001	Product loading rack (when loading diesel)	-
Coal conveying and storage	EU-1006	Storage tanks	T1 - T26
Coal dryer heater	EU-1007	Residue processing	EU-50nn
Coal milling and drying	EU-1008	Boiler	EU-6000
Additive unloading, storage, and processing	EU-15nn	Cooling tower (each of 3 cells)	EU-6001 EU-6002 EU-6003
Veba Combi Cracker (VCC) operations	EU-20nn	Emergency engine fuel tanks	EU-6005 EU-6007
Feed heater	EU-2001	Emergency generator	EU-6006
Treat gas heater	EU-2002	Emergency fire pump	EU-6008
Vacuum column feed heater	EU-2003	Lime handling and storage	EU-65nn
Fractionator heater	EU-2004	Hydrogen plant reformer 1	EU-7001
Sulfur recovery operations	EU-30nn	Hydrogen plant reformer 2	EU-7002
Flare pilots	EU-4001 EU-4002 EU-4003 EU-4004	Hydrogen plant deaeration vent 1	EU-7003
HP flare operations	-	Hydrogen plant deaeration vent 2	EU-7004
LP flare operations	-		
SB flare operations	-		

(b) Vacuum producing systems, wastewater separators, and process turnarounds in petroleum refineries are not subject to 326 IAC 8-1-6 because these operations are subject to other rules in 326 IAC 8. These operations are subject to 326 IAC 8-4-2.

(c) Pursuant to 326 IAC 8-1-6 (New Facilities; General Reduction Requirements), the Permittee shall control VOC emissions from the units listed in the table below using the Best Available Control Technology (BACT), which has been determined to be the following:

Description	Unit ID
HP Flare	-
Product loading rack (when loading naphtha)	-
Wastewater collection and treatment	-

BACT for these units has been determined to be the following:

(1) BACT for the HP Flare operations shall be as follows:

(A) The overall VOC control efficiency, including capture efficiency and destruction efficiency, for the HP Flare shall be 98% or greater when flaring a process stream.

(2) BACT for the Product Loading Rack when loading naphtha shall be as follows:

(A) The Product Loading Rack shall use only submerged loading.

(B) The overall VOC control efficiency, including capture efficiency and destruction efficiency, for the Product Loading Flare shall be 98% or greater.

(C) VOC emissions shall not exceed:

Emission Limitations	
Product	**lb/kgal**[1]
naphtha	0.049

1. kgal = 1,000 gallons

(3) VOC emissions from the wastewater treatment vent (EU-8001), oily water sump (EU-8002), and manhole no. 1 (EU-8003) shall not exceed 20 parts per million by volume (dry) (ppmvd), each.

326 IAC 8-4 (Petroleum Sources)
Pursuant to 326 IAC 8-4-1(c), sections 2 through 5 and 7 through 9 of apply to all new sources of the types described in this rule as of January 1, 1980.

(a) Pursuant to 326 IAC 8-4-2 (Petroleum Refineries):

(1) Vacuum Systems: No owner or operator of any vacuum producing systems at a petroleum refinery may cause, allow or permit the emission of any noncondensable volatile organic compounds from the condensers, hot wells or accumulators of the system.

(2) Wastewater Separators: The owner or operator of any wastewater (oil/water) separators at a petroleum refinery shall equip all separators, forebay, and openings in covers with lids or seals such that the lids or seals are in the closed position at all times except when in actual use.

(3) Process Turnaround: The owner or operator of a petroleum refinery shall notify the commissioner thirty (30) days prior to a process unit turnaround. In addition, the owner or operator shall minimize volatile organic compound emissions during turnaround, by providing for:

(A) Depressurization venting of the process unit or vessel to a vapor recovery system, flare or firebox; and
(B) No emission of volatile organic compounds from a process unit or vessel until its internal pressure is 136 kPa (19.7 psi) or less.

(b) Storage vessels at the source with capacities greater than one hundred fifty thousand (150,000) liters (thirty nine thousand (39,000) gallons) contain volatile organic compounds whose true vapor pressure at the highest monthly average daily temperature of 78.3°F is less than or equal to 10.5 kPa (1.52 psia). The true vapor pressure of product naphtha, the highest of the liquids stored, is 8.07 kPa (1.17 psia) at 78.3°F. Therefore, the requirements of 326 IAC 8-4-3 are not applicable to storage vessels at the source.

(c) 326 IAC 8-4-4 (Bulk Gasoline Terminals) is not applicable to the source. The source is not a bulk gasoline terminal as defined at 326 IAC 1-2-8. The source is not a gasoline storage facility which receives gasoline from refineries primarily by pipeline, ship, barge or rail, and delivers gasoline to bulk gasoline plants or to commercial or retail accounts primarily by transport.

(d) 326 IAC 8-4-5 (Bulk Gasoline Plants) is not applicable to the source. The source is not a bulk gasoline plant as defined at 326 IAC 1-2-7. The source is not a gasoline storage and distribution facility which receives gasoline from bulk terminals by transport, stores it in tanks, and subsequently dispenses it via account trucks to local farms, businesses, and service stations.

(e) 326 IAC 8-4-7 (Gasoline Transports) is not applicable to the source. The source is not an owner or operator of gasoline transports as defined at 326 IAC 1-2-84. The definition of "transport" is: a tractor semi-trailer capable of hauling a maximum load permissible by law of liquid petroleum products with various sized compartment and typically a total capacity of approximately eight thousand (8,000) gallons.

(f) The requirements of 326 IAC 8-4-8 (Leaks from Leaks from Petroleum Refineries; Monitoring; Reports) is not applicable to the source. The source is a petroleum refinery as defined in 40 CFR 60 and 40 CFR 63. However, because the dates for initial submissions and reports under this rule are past, IDEM, OAQ considers that leak detection and repair provisions of other rules applicable to this source, including but not limited to 40 CFR 60, Subpart GGGa, comply with the intent of this rule.

(g) 326 IAC 8-4-9 (Leaks from Transports and Vapor Collection Systems; Records) is not applicable to the source. The source is not an owner or operator of a vapor balance system or vapor control system at a source subject to 326 IAC 8-4-4, 326 IAC 8-4-5, or 326 IAC 8-4-6 or of gasoline transports subject to 326 IAC 8-4-7.

326 IAC 8-5 (Miscellaneous Operations)
The source is not subject to 326 IAC 8-5 because it is not one of the types of sources listed in 326 IAC 8-5-2 through 326 IAC 8-5-6.

326 IAC 8-6 (Organic Solvent Emission Limitations)
The source is not subject to 326 IAC 8-6 because it is not one of the categories of sources listed in 326 IAC 8-6-1. The source is not an existing source (as of January 1, 1980), located in Lake and Marion Counties, or a source commencing operation after October 7, 1974, and prior to January 1, 1980, located anywhere in the state, with potential emissions of 90.7 megagrams (100 tons) or greater per year of VOC, not limited by other rules in 326 IAC 8.

326 IAC 8-7 (Specific VOC Reduction Requirements for Lake/Porter/Clark/Floyd Counties)
The source is not subject to 326 IAC 8-7 because it is not located in Lake, Porter, Clark, or Floyd Counties.

326 IAC 8-9 (Volatile Organic Liquid Storage Vessels)
The source is not subject to 326 IAC 8-9 because it is not located in Lake, Porter, Clark, or Floyd Counties.

326 IAC 8-18 (Synthetic Organic Chemical Manufacturing Industry Air Oxidation, Distillation, and Reactor Processes)
The source is not subject to 326 IAC 8-18 because it is not located in Lake or Porter Counties.

326 IAC 8-19 (Control of Volatile Organic Compound Emissions from Process Vents in Batch Operations)
The source is not subject to 326 IAC 8-19 because it is not located in Lake or Porter Counties.

326 IAC 8-20 (Industrial Wastewater)
The source is not subject to 326 IAC 8-20 because it is not located in Lake or Porter Counties.

326 IAC 9 (Carbon Monoxide Emission Limits)
The source is a stationary source of carbon monoxide emissions commencing operation after March 21, 1972. However, the source is not a source for which an emission limit has been established in 326 IAC 9-1-2. The VCC operations (Block 2000) are not a catalyst regeneration petroleum cracking system or a petroleum fluid coker as described at 326 IAC 9-1-2(a)(1). Operations at the source are not ferrous metal smelters or refuse incineration and refuse burning equipment as described at 326 IAC 9-1-2(a)(2) or (3). Therefore, the source is not subject to the requirements of 326 IAC 9-1.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to assure 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.

(a) The Compliance Determination Requirements applicable to this proposed Part 70 permit are as follows:

(1) The following control devices for particulate control shall be in operation and control particulate emissions from the associated coal handling emission units at all times those emission units are in operation:

Emission Unit Description	Unit ID	Control Device
Railcar unloading	EU-1000	Baghouse EU-1000 Water spray dust suppression (hoppers & feeders only)
Transfer station	EU-1001	Baghouse EU-1001
Coal storage enclosure 1 Coal storage enclosure 2 Reclaim transfer station	EU-1006	Baghouse EU-1006
Coal drying loop	EU-1008	Baghouse EU-1008
Enclosed screw conveyor to Block 2000 feed premix drum	EU-2005	Coal Handling System Filter EU-2005

(2) The following control devices for particulate control shall be in operation and control particulate emissions from the associated solids handling emission units at all times those emission units are in operation:

Emission Unit Description	Unit ID	Control Device ID
Coarse additive unloading	silo T34	Baghouse EU-1501
Fine additive unloading	silo T33	Baghouse EU-1502
Na_2S unloading	silo T35	Baghouse EU-1503
Fine additive production system	-	Baghouse EU-1504
Coarse additive transfer system	Coarse Additive Screw Conveyor	Filter EU-2006
Fine additive transfer system	Fine Additive Transfer	Filter EU-2007
Na_2S slurry preparation system	Na_2S Slurry Preparation	Filter EU-2008

(3) The following equation shall be used to determine the CO_2e emissions from EU-1007, EU-2001, EU-2002, EU-2003, EU-2004, and EU-6000:

$$E_{GHGi} = F_i \times 60.12\ ^{tons}/_{MMCF}$$

Where:

E_{GHGi} = CO_2e emissions for unit *i*, tons/month
F_i = fuel gas usage in unit *i*, MMCF/month
i = fuel combustion unit ID

(4) The following equation shall be used to determine the CO_2e emissions from EU-3001 and EU-3002:

$$E_{GHGSB} = \text{Sulfur production (tons/month)} \times 0.641 \text{ (ton } CO_2e\text{/ton S)}$$

Where:

E_{GHGSB} = CO_2e emissions (ton/month) for the sulfur recovery systems (TGTUA and TGTUB)

(5) The following equation shall be used to determine the CO_2e emissions from the HP Flare, LP Flare, and Sulfur Block Flare:

$$E_{FLAi} = F_i \text{ (MMCF/month)} \times 60.36 \text{ (ton } CO_2e\text{/MMCF fuel gas)}$$

Where:

E_{FLAi} = CO_2e emissions for flare *i*, (ton/month)
F_i = Monthly sweep and pilot fuel gas usage in flare *i*, (MMCF/month)
i = flare identifier

(6) The LP Flare for VOC control shall be in operation and control VOC emissions from the slop tank at all times the slop tank is in operation.

(7) The Sulfur Block Flare for hydrogen sulfide control shall be in operation and control hydrogen sulfide emissions from sour water tanks T18 - T21 at all times sour water tanks T18 - T21 are in operation.

(8) Swing tank product changes

(A) In any twelve (12) consecutive month period during which tank T6 does not change between naphtha and diesel service, tank T6 shall be determined to be in compliance with the VOC emission limit in the table in Condition D.6.1 for the product in service.

(B) In any twelve (12) consecutive month period during which tank T6 changes between naphtha and diesel service, tank T6 shall be determined to in compliance with the VOC emission limit in Condition D.6.1 if the result, C, of the calculation below is less than or equal to 1.

$$C = \frac{D_N \times 6.29}{2{,}295} + \frac{(365 - D_N) \times 0.95}{345}$$

Where C = compliance determination coefficient
D_N = actual number of days in naphtha service during the twelve (12) consecutive month period

(9) Loading Flare

(A) The Loading Flare shall be determined to be in compliance with Conditions D.7.1(b)(1), (d)(1), (e)(1), and (f)(1) at all times that the flares burn only gaseous fuel that complies with Condition D.7.1(c).

(B) Prior to such time as the source shall conduct the testing required in Condition D.7.4, the Loading Flare shall be determined to be in compliance with Condition D.7.1(b)(2), (d)(2), (e)(2), and (f)(2) at all times that the source can demonstrate that the flares were designed to comply with 40 CFR 60.18.

(10) The Loading Flare for VOC control shall be in operation and control emissions from the Product Loading Rack facility at all times the Product Loading Rack facility is in operation.

(11) The following equation shall be used to determine the CO_2e emissions from the Loading Flare

$$E_{LDG} = F_{LDG} \times 60.36\ \frac{\text{tons}}{\text{MMCF}} + L_N \times 3.77\text{E-03}\ \frac{\text{tons}}{\text{kgal}} + L_D \times 2.06\text{E-04}\ \frac{\text{tons}}{\text{kgal}}$$

Where:

E_{FLA} = CO_2e emissions (ton/month) for the Loading Flare
F_{LDG} = Fuel gas usage in the Loading Flare (MMCF/month)
L_N = Monthly naphtha loadout (kgal/month)
L_D = Monthly diesel loadout (kgal/month)
kgal = 1,000 gallons

(12) The following control devices for particulate control shall be in operation and control particulate emissions from the associated residue handling emission units at all times those emission units are in operation:

Emission Unit Description	Unit ID	Control Device ID
Residue container loading and residue transfer conveyors	EU-5009	Filter EU-5009
Residue rail storage silo, loading hoppers, and residue transfer conveyors	EU-5005, EU-5006, EU-5010	Filter EU-5010
Residue swing storage silo, loading hoppers, and residue transfer conveyors	EU-5007, EU-5008, EU-5011	Filter EU-5011

(13) The drift eliminators for particulate control shall be in operation and control emissions from the cooling tower at all times the cooling tower is in operation.

(14) The following equation shall be used to determine the CO_2e emissions from the Emergency Generator (EU-6006) and Emergency Fire Pump (EU-6008):

(A)

$$E_{6006} = H_{6006} \times 1.62\ \frac{\text{tons}}{\text{hr}}$$

Where:

E_{RICE} = CO_2e emissions for non-emergency operation of the Emergency Generator (EU-6006), (ton/month)

H_{6008} = Monthly hours of non-emergency operation of the Emergency Generator (EU-6006), (hr/month)

(B)

$$E_{6008} = H_{6008} \times 0.43\ \frac{\text{tons}}{\text{hr}}$$

Where:

E_{6008} = CO_2e emissions for operation of the Emergency Fire Pump (EU-6008), (ton/month)
H_{6008} = Monthly hours of operation of the Emergency Fire Pump (EU-6008), (hr/month)

(15) The selective catalytic reduction (SCR) systems for NOx control shall be in operation and control emissions from the hydrogen plant reformers (EU-7001 and/or EU-7002) facility at all times the EU-7001 and/or EU-7002 facility are in operation.

(16) The following equation shall be used to determine the CO_2e emissions from hydrogen production operations:

(A)

$$E_{HYi} = H_{HYi} \text{ x } 112.59 \text{ (tons } CO_2e\text{/hr)}$$

Where:

E_{HYi} = CO_2e emissions for hydrogen plant *i*, (ton/month)
H_{HYi} = Monthly hours of operation of hydrogen plant *i*, (hr/month)
i = indicator for hydrogen plant 1 or 2

(B)

$$E_{DAi} = H_{DAi} \text{ x } 0.12 \text{ (tons } CO_2e\text{/hr)}$$

Where:

E_{DAi} = CO_2e emissions for DA vent *i*, (ton/month)
H_{DAi} = Monthly hours of operation of DA vent, *i* (hr/month)
i = indicator for hydrogen plant 1 or 2

(17) The following control devices for particulate control shall be in operation and control particulate emissions from the associated lime unloading emission units at all times those emission units are in operation:

Emission Unit Description	Unit ID	Control Device ID
Lime unloading	EU-6501	Filter EU-6501

Summary of Testing Requirements

Emission Unit	Control Device	Timeframe for Testing	Pollutant	Frequency of Testing	Authority
Railcar unloading	Baghouse EU-1000	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
		60/180[2]	Opacity	Every 90 days[3]	40 CFR 60, Subpart Y
Transfer station	Baghouse EU-1001	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2

Summary of Testing Requirements					
Emission Unit	**Control Device**	**Timeframe for Testing**	**Pollutant**	**Frequency of Testing**	**Authority**
		60/180[2]	Opacity	Every 90 days[3]	40 CFR 60, Subpart Y
Coal storage enclosure 1 Coal storage enclosure 2 Reclaim transfer station	Baghouse EU-1006	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
		60/180[2]	Opacity	Every 90 days[3]	40 CFR 60, Subpart Y
Coal dryer heater, EU-1007	-	180[1]	$PM_{FILTERABLE}$, PM_{10}, $PM_{2.5}$, NOx, VOC, CO	Every 5 years	326 IAC 2-2
		60/180[2]	NOx	Every 2 years	40 CFR 60, Subpart Ja
Coal drying loop purge	Baghouse EU-1008	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
Coarse additive unloading	Baghouse EU-1501	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
Fine additive unloading	Baghouse EU-1502	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
Na_2S unloading	Baghouse EU-1503	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
Fine additive production system	Baghouse EU-1504	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
Feed heater, EU-2001	-	180[1]	$PM_{FILTERABLE}$, PM_{10}, $PM_{2.5}$, VOC, CO	Every 5 years	326 IAC 2-2
Treat gas heater, EU-2002	-	180[1]	$PM_{FILTERABLE}$, PM_{10}, $PM_{2.5}$, NOx, VOC, CO	Every 5 years	326 IAC 2-2
		60/180[2]	NOx	Every 2 years	40 CFR 60, Subpart Ja
Vacuum column feed heater, EU-2003	-	180[1]	$PM_{FILTERABLE}$, PM_{10}, $PM_{2.5}$, NOx, VOC, CO	Every 5 years	326 IAC 2-2
Fractionator heater, EU-2004	-	180[1]	$PM_{FILTERABLE}$, PM_{10}, $PM_{2.5}$, VOC, CO	Every 5 years	326 IAC 2-2
Enclosed screw conveyor to Block 2000 feed premix drum	Filter EU-2005	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
		60/180[2]	Opacity	Every 90 days[3]	40 CFR 60, Subpart Y
Coarse additive transfer system	Filter EU-2006	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
Fine additive transfer system	Filter EU-2007	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
Na_2S slurry preparation system	Filter EU-2008	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2

Summary of Testing Requirements

Emission Unit	Control Device	Timeframe for Testing	Pollutant	Frequency of Testing	Authority
Tail gas treatment unit A, EU-3001	-	180[1]	$PM_{FILTERABLE}$, PM_{10}, $PM_{2.5}$, NOx, VOC, CO, H_2SO_4 mist	Every 5 years	326 IAC 2-2
Tail gas treatment unit B, EU-3002	-	180[1]	$PM_{FILTERABLE}$, PM_{10}, $PM_{2.5}$, NOx, VOC, CO, H_2SO_4 mist	Every 5 years	326 IAC 2-2
HP flare	-	first planned event	net heating value, actual exit velocity, visible emissions	Every 5 years	326 IAC 2-2
LP flare	-	first planned event	net heating value, actual exit velocity, visible emissions	Every 5 years	326 IAC 2-2
SB flare	-	first planned event	net heating value, actual exit velocity, visible emissions	Every 5 years	326 IAC 2-2
Loading flare while loading naphtha	-	180[1]	net heating value, actual exit velocity, visible emissions	Every 5 years	326 IAC 2-2
Loading flare while loading diesel	-	180[1]	net heating value, actual exit velocity, visible emissions	Every 5 years	326 IAC 2-2
Product loading rack while loading naphtha	Loading flare	180[1]	VOC input to flare	Every 5 years	326 IAC 2-2
Product loading rack while loading diesel	Loading flare	180[1]	VOC input to flare	Every 5 years	326 IAC 2-2
Residue pastillator line, EU-5001a-d	-	180[1]	VOC	Every 5 years	326 IAC 2-2
Residue pastillator line, EU-5002a-d	-	180[1]	VOC	Every 5 years	326 IAC 2-2
Residue pastillator line, EU-5003a-d	-	180[1]	VOC	Every 5 years	326 IAC 2-2

Summary of Testing Requirements					
Emission Unit	**Control Device**	**Timeframe for Testing**	**Pollutant**	**Frequency of Testing**	**Authority**
Residue pastillator line, EU-5004a-d	-	180[1]	VOC	Every 5 years	326 IAC 2-2
Residue container loading and transfer conveyors	Filter EU-5009	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
Residue rail storage silo, loading hoppers, and transfer conveyors	Filter EU-5010	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
Residue swing storage silo, loading hoppers, and transfer conveyors	Filter EU-5011	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
Boiler, EU-6000	-	180[1]	$PM_{FILTERABLE}$, PM_{10}, $PM_{2.5}$, NOx, VOC, CO	Every 5 years	326 IAC 2-2
		60/180[2]	NOx	Every 2 years	40 CFR 60, Subpart Ja
Lime unloading	Filter EU-6501	180[1]	PM, PM_{10}, $PM_{2.5}$	Every 5 years	326 IAC 2-2
Hydrogen plant reformer 1, EU-7001	-	180[1]	$PM_{FILTERABLE}$, PM_{10}, $PM_{2.5}$, VOC, CO	Every 5 years	326 IAC 2-2
Hydrogen plant reformer 2, EU-7002	-	180[1]	$PM_{FILTERABLE}$, PM_{10}, $PM_{2.5}$, VOC, CO	Every 5 years	326 IAC 2-2
Hydrogen plant 1 DA vent, EU-7003	-	180[1]	VOC, CO	Every 5 years	326 IAC 2-2
Hydrogen plant 2 DA vent, EU-7004	-	180[1]	VOC, CO	Every 5 years	326 IAC 2-2
Wastewater treatment system vent, EU-8001	-	180[1]	VOC	Every 5 years	326 IAC 2-2

Notes:

1. *180 days after startup*
2. *Within 60 days of achieving maximum capacity but not later than 180 days after startup*
3. *If the any 6-minute average opacity reading in the most recent performance test is less than or equal to 50% of the applicable standard, a new opacity test must be conducted within 12 months of the date of the previous test.*

(b) The Compliance Monitoring Requirements applicable to this proposed Part 70 permit are as follows:

(1) Coal handling:

Control	Parameter	Frequency	Range	Excursions and Exceedances
Baghouse EU-1000	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps
Baghouse EU-1001	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps
Baghouse EU-1006	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps
Baghouse EU-1008	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps
Filter EU-2005	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps
Coal unloading enclosure	Negative pressure, or	Daily	greater than 0.013 mm Hg	Response Steps
	Air flow	Daily	200 ft/min	
	Enclosure inspection	Monthly	Satisfactory/ unsatisfactory	
Coal storage enclosure 1	Negative pressure, or	Daily	greater than 0.013 mm Hg	Response Steps
	Air flow	Daily	200 ft/min	
	Enclosure inspection	Monthly	Satisfactory/ unsatisfactory	
Coal storage enclosure 2	Negative pressure	Daily	greater than 0.013 mm Hg	Response Steps
	Air flow	Daily	200 ft/min	
	Enclosure inspection	Monthly	Satisfactory/ unsatisfactory	

These monitoring conditions are necessary because the baghouses, filter, and enclosures for the coal handling operations must operate properly to assure compliance with 326 IAC 2-2 (Prevention of Significant Deterioration (PSD) Requirements).

(2) Solids handling:

Control	Parameter	Frequency	Range	Excursions and Exceedances
Baghouse EU-1501	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps
Baghouse EU-1502	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps
Baghouse EU-1503	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps
Baghouse EU-1504	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps
Filter EU-2006	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps

Control	Parameter	Frequency	Range	Excursions and Exceedances
Filter EU-2007	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps
Filter EU-2008	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps

These monitoring conditions are necessary because the baghouses and filters for the solids handling operations must operate properly to assure compliance with 326 IAC 2-2 (Prevention of Significant Deterioration (PSD) Requirements).

(3) Fuel gas combustion:

(A) Continuous emissions monitoring systems (CEMS):

Unit	Parameter	Frequency	Excursions and Exceedances	Authority	Reporting
EU-1007	O_2 CEMS Total sulfur in fuel gas	Continuous	Response Steps	40 CFR 60, Subpart Ja	Quarterly for calibration gas audits and RATA, and CEMS downtime
EU-2001	NOx CEMS Total sulfur in fuel gas	Continuous	Response Steps	40 CFR 60, Subpart Ja	Quarterly for calibration gas audits and RATA, and CEMS downtime
EU-2002	O_2 CEMS Total sulfur in fuel gas	Continuous	Response Steps	40 CFR 60, Subpart Ja	Quarterly for calibration gas audits and RATA, and CEMS downtime
EU-2003	Total sulfur in fuel gas	Continuous	Response Steps	40 CFR 60, Subpart Ja	Quarterly for calibration gas audits and RATA, and CEMS downtime
EU-2004	NOx CEMS Total sulfur in fuel gas	Continuous	Response Steps	40 CFR 60, Subpart Db 40 CFR 60, Subpart Ja	Quarterly for calibration gas audits and RATA, and CEMS downtime
EU-6000	O_2 CEMS Total sulfur in fuel gas	Continuous	Response Steps	40 CFR 60, Subpart Ja	Quarterly for calibration gas audits and RATA, and CEMS downtime

(B) CEMS downtime monitoring:

Control	Parameter	Frequency	Range	Excursions and Exceedances
O_2 CEMS: EU-1007 EU-2001 EU-2002 EU-6000	stack percent oxygen	once per day	as determined by CEMS	Response steps
NOx CEMS: EU-2001	stack percent oxygen	once per day	as determined by CEMS	Response steps
Total Sulfur Continuous Analyzer: EU-1007 EU-2001 EU-2002 EU-2003 EU-2004 EU-6000	fuel gas sulfur	once per hour	≤ 0.005 gr/dscf	Response steps

These monitoring conditions are necessary because the fuel gas combustion units must operate properly to assure compliance with 326 IAC 2-2 (Prevention of Significant Deterioration (PSD) Requirements) and 40 CFR 60.

(4) Sulfur recovery units:

(A) Continuous emissions monitoring systems (CEMS):

Unit	Parameter	Frequency	Excursions and Exceedances	Authority	Reporting
Tail gas incinerator A-605A	SO_2 CEMS	Continuous	Response Steps	326 IAC 2-2 (PSD)	Quarterly for calibration gas audits and RATA, and CEMS downtime
Tail gas incinerator A-605B	SO_2 CEMS	Continuous	Response Steps	326 IAC 2-2 (PSD)	Quarterly for calibration gas audits and RATA, and CEMS downtime

(B) CEMS downtime monitoring:

Control	Parameter	Frequency	Range	Excursions and Exceedances
Tail gas incinerator A-605A	H_2S in T-602A offgas	Drager tube, once per hour	*TBD*	Response steps
Tail gas incinerator A-605B	H_2S in T-602A offgas	Drager tube, once per hour	*TBD*	Response steps

These monitoring conditions are necessary because the sulfur recovery units must operate properly to assure compliance with 326 IAC 2-2 (Prevention of Significant Deterioration (PSD) Requirements) and 40 CFR 60.

(5) Flares:

(A) Continuous emissions monitoring systems (CEMS):

Unit	Parameter	Frequency	Excursions and Exceedances	Authority	Reporting
HP flare	Total sulfur in fuel gas	Continuous	Response Steps	40 CFR 60, Subpart Ja	Quarterly for calibration gas audits and RATA, and CEMS downtime
	Flare pilot	Continuous	Response Steps	326 IAC 2-2 (PSD)	Records of the presence of a pilot
LP flare	Total sulfur in fuel gas	Continuous	Response Steps	40 CFR 60, Subpart Ja	Quarterly for calibration gas audits and RATA, and CEMS downtime
	Flare pilot	Continuous	Response Steps	326 IAC 2-2 (PSD)	Records of the presence of a pilot
SB flare	Total sulfur in fuel gas	Continuous	Response Steps	40 CFR 60, Subpart Ja	Quarterly for calibration gas audits and RATA, and CEMS downtime
	Flare pilot	Continuous	Response Steps	326 IAC 2-2 (PSD)	Records of the presence of a pilot
Loading flare	Total sulfur in fuel gas	Continuous	Response Steps	40 CFR 60, Subpart Ja	Quarterly for calibration gas audits and RATA, and CEMS downtime
	Flare pilot	Continuous	Response Steps	326 IAC 2-2 (PSD)	Records of the presence of a pilot

These monitoring conditions are necessary because the flares must operate properly to assure compliance with 326 IAC 2-2 (Prevention of Significant Deterioration (PSD) Requirements) and 40 CFR 60.

(6) Residue handling:

(A) Filters

Control	Parameter	Frequency	Range	Excursions and Exceedances
Filter EU-5009	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps
Filter EU-5010	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps
Filter EU-5011	Water Pressure Drop	Daily	3.0 - 6.0 inches of water	Response Steps

These monitoring conditions are necessary because the filters for the residue handling operations must operate properly to assure compliance with 326 IAC 2-2 (Prevention of Significant Deterioration (PSD) Requirements).

(B) Loading

Control	Parameter	Frequency	Range	Excursions and Exceedances
Railcar loading choke flow-practices	Visible Emissions	Daily	Normal/ abnormal	Response Steps
Swing loading choke flow-practices	Visible Emissions	Daily	Normal/ abnormal	Response Steps

(7) Cooling tower:

Control	Parameter	Frequency	Range	Excursions and Exceedances
Cell EU-6001	TDS	once per week	≤2,395 mg/l	Response Steps
	Presence of liquid VOC in return	once per week	none visible	
Cell EU-6002	TDS	once per week	≤2,395 mg/l	Response Steps
	Presence of liquid VOC in return	once per week	none visible	
Cell EU-6003	TDS	once per week	≤2,395 mg/l	Response Steps
	Presence of liquid VOC in return	once per week	none visible	

These monitoring conditions are necessary because the cooling tower must operate properly to assure compliance with 326 IAC 2-2 (Prevention of Significant Deterioration (PSD) Requirements).

(8) Hydrogen production plants:

(A) Continuous emissions monitoring systems (CEMS):

Unit	Parameter	Frequency	Excursions and Exceedances	Authority	Reporting
EU-7001	NOx CEMS	Continuous	Response Steps	40 CFR 60, Subpart Db	Quarterly for calibration gas audits and RATA, and CEMS downtime
	Total sulfur in fuel gas			40 CFR 60, Subpart Ja	
EU-7002	NOx CEMS	Continuous	Response Steps	40 CFR 60, Subpart Db	Quarterly for calibration gas audits and RATA, and CEMS downtime
	Total sulfur in fuel gas			40 CFR 60, Subpart Ja	

(B) CEMS downtime monitoring:

Control	Parameter	Frequency	Range	Excursions and Exceedances
EU-7001 SCR	ammonia flow rate	four (4) times per hour	*TBD*	Response steps
	inlet duct temperature		*TBD*	
EU-7002 SCR	ammonia flow rate	four (4) times per hour	*TBD*	Response steps
	inlet duct temperature		*TBD*	

These monitoring conditions are necessary because the hydrogen production plants must operate properly to assure compliance with 326 IAC 2-2 (Prevention of Significant Deterioration (PSD) Requirements) and 40 CFR 60.

(9) Lime unloading:

Control	Parameter	Frequency	Range	Excursions and Exceedances
Filter EU-6501	Inspection	twice per year	manufacturer's specifications	Response Steps

These monitoring conditions are necessary because the lime unloading filter must operate properly to assure compliance with 326 IAC 2-2 (Prevention of Significant Deterioration (PSD) Requirements).

(10) Wastewater:

Control	Parameter	Frequency	Range	Excursions and Exceedances
Oily water sump carbon canister (EU-8002)	Exhaust VOC concentration or	Daily[1]	<20 ppmvd	Response Steps
	Exhaust benzene concentration	Daily[1]	1 ppmvd	

Control	Parameter	Frequency	Range	Excursions and Exceedances
Manhole No. 1 carbon canister (EU-8003)	Exhaust VOC concentration or	Daily[1]	<20 ppmvd	Response Steps
	Exhaust benzene concentration	Daily[1]	1 ppmvd	

1. *Monitoring shall be conducted each day or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater.*

These monitoring conditions are necessary because the carbon canisters for VOC control must operate properly to assure compliance with 326 IAC 2-2 (Prevention of Significant Deterioration (PSD) Requirements).

Conclusion and Recommendation

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant. An application for the purposes of this review was received on January 25, 2018*.*

The staff recommends to the Commissioner that the proposed Part 70 permit be approved.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Doug Logan at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 234-5328 or toll free at 1-800-451-6027, extension 4-5328.

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

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: http://www.in.gov/idem/airquality/2356.htm; and the Citizens' Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

Appendix A: Emission Calculations
PTE Summary

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

Uncontrolled Potential to Emit (tons/yr)												
Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$[1]**	**SO_2**	**NOx**	**VOC**	**CO**	**CO2e**	**Sulfuric Acid**	**Hydrogen Sulfide**	**Total Reduced Sulfur**	**Ammonia**
Coal Handling (Block 1000)	29503.25	4377.35	1319.81	-	-	-	-	-	-	-	-	-
Coal Drying Heater (EU-1007)	0.46	1.84	1.84	0.44	9.78	1.33	8.80	29,127	-	-	-	-
Additive Handling (Block 1500)	193.91	186.04	186.04	-	-	-	-	-	-	-	-	-
Solids Handling (Block 2000)	661.21	180.33	180.33	-	-	-	-	-	-	-	-	-
Feed Heater EU-2001	1.06	4.24	4.24	1.00	22.50	3.07	20.25	67,023	-	-	-	-
Treat Gas Heater EU-2002	0.44	1.74	1.74	0.41	9.25	1.26	8.33	27,561	-	-	-	-
Vacuum Column Feed Heater EU-2003	0.07	0.30	0.30	0.07	1.58	0.21	1.42	4,698	-	-	-	-
Fractionator Heater EU-2004	1.29	5.15	5.15	1.22	27.33	3.72	24.60	81,430	-	-	-	-
Sulfur Recovery (Block 3000)	0.61	2.46	2.46	127.46	33.00	0.46	234.32	40,872	8.05	5.11	4.13	-
HP, LP, SB Flares	0.13	0.50	0.50	66.66	11.99	31.61	40.97	15,908	-	-	-	-
Loading Rack Flare (EU-4001)					0.20		0.90	425				
Product loading rack	-	-	-	-	-	143.82	-	-	-	-	-	-
Block 4000 Storage Tanks	-	-	-	-	-	12.67	-	-	-	-	-	-
Residue Solidification Units (Block 5000)	2.03	0.74	0.74	-	-	18.37	-	-	-	-	-	-
Boiler EU-6000	0.56	2.26	2.26	0.53	12.00	1.64	10.80	35,756	-	-	-	-
Cooling Tower EU-6001, EU-6002, EU-6003)	0.84	0.48	1.75E-03	-	-	5.89	-	-	-	-	-	0.30
Fuel tanks (EU-6005, EU-6007)	-	-	-	-	-	0.001	-	-	-	-	-	-
Emergency Engines (EU-6006, EU-6008)	0.29	0.29	0.29	1.08E-02	8.60	8.60	5.11	1,029	-	-	-	-
Lime Storage & Handling (Block 6500)	275.06	96.36	96.36	-	-	-	-	-	-	-	-	-
Hydrogen Plant (Block 7000)	44.08	44.08	44.08	10.40	477.50	72.11	146.92	1,972,542	-	-	-	-
Wastewater Treatment (Block 8000)	-	-	-	-	-	41.17	-	-	-	-	-	-
Total Non-Fugitive	**30685.29**	**4904.15**	**1846.14**	**208.20**	**613.72**	**345.94**	**502.41**	**2,276,371**	**8.1**	**5.1**	**4.1**	**0.3**
Fugitive Emissions												
Leaks	-	-	-	-	-	349.03	-	-	-	-	-	-
Paved Roads	11.69	2.34	0.57	-	-	-	-	-	-	-	-	-
Total	**30,697**	**4,906**	**1,847**	**208**	**614**	**695**	**502**	**2,276,371**	**8.05**	**5.11**	**4.13**	**0.30**

Notes:

1. $PM_{2.5}$ listed is direct $PM_{2.5}$

Appendix A: Emission Calculations
PTE Summary

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

Potential to Emit after Control (tons/yr)

Emission Unit	PM	PM_{10}	$PM_{2.5}$[1]	SO_2	NOx	VOC	CO	CO2e	Sulfuric Acid	Hydrogen Sulfide	Total Reduced Sulfur	Ammonia
Coal Handling (Block 1000)	2.85	2.85	2.85	-	-	-	-	-	-	-	-	-
Coal Drying Heater (EU-1007)	0.46	1.84	1.84	0.44	9.78	1.33	8.80	29,127	-	-	-	-
Additive Handling (Block 1500)	0.23	0.23	0.23	-	-	-	-	-	-	-	-	-
Solids Handling (Block 2000)	0.05	0.05	0.05	-	-	-	-	-	-	-	-	-
Feed Heater EU-2001	1.06	4.24	4.24	1.00	22.50	3.07	20.25	67,023	-	-	-	-
Treat Gas Heater EU-2002	0.44	1.74	1.74	0.41	9.25	1.26	8.33	27,561	-	-	-	-
Vacuum Column Feed Heater EU-2003	0.07	0.30	0.30	0.07	1.58	0.21	1.42	4,698	-	-	-	-
Fractionator Heater EU-2004	1.29	5.15	5.15	1.22	27.33	3.72	24.60	81,430	-	-	-	-
Sulfur Recovery (Block 3000)	0.61	2.44	2.44	144.39	33.00	1.78	27.06	40,872	8.05	5.11	4.13	-
HP, LP, SB Flares	0.13	0.50	0.50	66.66	11.99	31.61	40.97	15,908	-	-	-	-
Loading Rack Flare (EU-4001)	-	-	-	-	0.20	-	0.90	425	-	-	-	-
Product loading rack	-	-	-	-	-	143.82	-	-	-	-	-	-
Block 4000 Storage Tanks	-	-	-	-	-	12.67	-	-	-	-	-	-
Residue Solidification Units (Block 5000)	0.03	0.03	0.03	-	-	18.37	-	-	-	-	-	-
Boiler EU-6000	0.56	2.26	2.26	0.53	12.00	1.64	10.80	35,756	-	-	-	-
Cooling Tower EU-6001, EU-6002, EU-6003)	0.84	0.48	1.75E-03	-	-	5.89	-	-	-	-	-	0.30
Fuel tanks (EU-6005, EU-6007)	-	-	-	-	-	0.001	-	-	-	-	-	-
Emergency Engines (EU-6006, EU-6008)	0.29	0.29	0.29	1.08E-02	8.60	8.60	5.11	1,029	-	-	-	-
Lime Storage & Handling (Block 6500)	0.04	0.04	0.04	-	-	-	-	-	-	-	-	-
Hydrogen Plant (Block 7000)	44.08	44.08	44.08	10.40	47.75	72.11	146.92	1,972,542	-	-	-	-
Wastewater Treatment (Block 8000)	-	-	-	-	-	1.65	-	-	-	-	-	-
Total	**53.04**	**66.51**	**66.03**	**225.13**	**183.97**	**307.73**	**295.15**	**2,276,371**	**8.05**	**5.11**	**4.13**	**0.30**
Fugitive Emissions												
Leaks	-	-	-	-	-	176.22	-	-	-	-	-	-
Paved Roads	11.69	2.34	0.57	-	-	-	-	-	-	-	-	-
Total	**64.7**	**68.9**	**66.6**	**225.1**	**184.0**	**484.0**	**295.1**	**2,276,371**	**8.05**	**5.11**	**4.13**	**0.30**

Notes:

1. $PM_{2.5}$ listed is direct $PM_{2.5}$

Potential to Emit after Issuance[1] (tons/yr)

Appendix A: Emission Calculations
PTE Summary

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

Emission Unit	PM	PM_{10}	$PM_{2.5}$[2]	SO_2	NOx	VOC	CO	CO2e	Sulfuric Acid	Hydrogen Sulfide	Total Reduced Sulfur	Ammonia
Coal Handling (Block 1000)	2.85	2.85	2.85	-	-	-	-	-	-	-	-	-
Coal Drying Heater (EU-1007)	0.46	1.83	1.83	0.35	7.33	1.32	8.92	29,127	-	-	-	-
Additive Handling (Block 1500)	0.23	0.23	0.23	-	-	-	-	-	-	-	-	-
Solids Handling (Block 2000)	0.05	0.05	0.05	-	-	-	-	-	-	-	-	-
Feed Heater EU-2001	1.07	4.22	4.22	0.80	16.87	3.04	20.53	67,023	-	-	-	-
Treat Gas Heater EU-2002	0.44	1.73	1.73	0.33	6.94	1.25	8.44	27,561	-	-	-	-
Vacuum Column Feed Heater EU-2003	0.07	0.30	0.30	0.06	1.18	0.21	1.44	4,698	-	-	-	-
Fractionator Heater EU-2004	1.30	5.12	5.12	0.97	20.50	3.69	24.94	81,430	-	-	-	-
Sulfur Recovery (Block 3000)	0.61	2.44	2.44	144.39	33.00	1.78	27.06	40,872	8.05	5.11	4.13	-
HP, LP, SB Flares	0.13	0.50	0.50	66.66	11.99	31.61	40.97	15,908	-	-	-	-
Loading Rack Flare (EU-4001)	0.002	0.01	0.01	0.001	0.29	0.01	0.98	559	-	-	-	-
Product loading rack	-	-	-	-	-	2.88	-	-	-	-	-	-
Block 4000 Storage Tanks	-	-	-	-	-	12.67	-	-	-	-	-	-
Residue Solidification Units (Block 5000)	0.03	0.03	0.03	-	-	18.37	-	-	-	-	-	-
Boiler EU-6000	0.57	2.25	2.25	0.42	9.00	1.62	10.95	35,756	-	-	-	-
Cooling Tower EU-6001, EU-6002, EU-6003)	0.84	0.48	0.002	-	-	5.89	-	-	-	-	-	0.30
Fuel tanks (EU-6005, EU-6007)	-	-	-	-	-	0.001	-	-	-	-	-	-
Emergency Engines (EU-6006, EU-6008)	0.07	0.07	0.07	0.003	1.97	1.97	1.24	249	-	-	-	-
Lime Storage & Handling (Block 6500)	0.04	0.04	0.04	-	-	-	-	-	-	-	-	-
Hydrogen Plant (Block 7000)	44.08	44.08	35.26	10.40	47.75	39.05	156.21	1,974,702	-	-	-	-
Wastewater Treatment (Block 8000)	-	-	-	-	-	1.65	-	-	-	-	-	-
Total	**52.85**	**66.23**	**56.94**	**224.37**	**156.83**	**127.00**	**301.67**	**2,277,884**	**8.05**	**5.11**	**4.13**	**0.30**
Fugitive Emissions												
Leaks	-	-	-	-	-	176.22	-	-	-	-	-	-
Paved Roads	11.69	2.34	0.57	-	-	-	-	-	-	-	-	-
Total	**64.54**	**68.57**	**57.51**	**224.37**	**156.83**	**303.22**	**301.67**	**2,277,884**	**8.05**	**5.11**	**4.13**	**0.30**

Notes:

1. The shaded cells indicate where limits are included.

2. $PM_{2.5}$ listed is direct $PM_{2.5}$

Appendix A: Emission Calculations
HAPs Summary

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

	Uncontrolled Potential to Emit (tons/yr)									
Emission Unit	Coal Handling Units	Coal Drying Heater EU-1007	Additive Handling	Block 2000 Solids	Feed Heater EU-2001	Treat Gas Heater EU-2002	Vacuum Column Feed Heater EU-2003	Fractionator Heater EU-2004	Sulfur recovery	HP LP SB Flare Pilots
Organic HAPs										
Acetaldehyde										
Acrolein										
Benzene	-	5.09E-04			1.17E-03	4.81E-04	8.20E-05	1.42E-03	4.86E-04	7.79E-06
o-cresol										
m+p-cresol										
Cumene										
Dichlorobenzene	-	2.91E-04			6.69E-04	2.75E-04	4.69E-05	8.13E-04		4.45E-06
Ethylbenzene					-	-	-	-	-	-
Formaldehyde	-	1.82E-02			4.18E-02	1.72E-02	2.93E-03	5.08E-02	1.73E-02	2.78E-04
n-Hexane		0.44			1.00	0.41	7.03E-02	1.22	0.42	6.68E-03
Methanol										
PAH, total										
Phenol										
Toluene		8.24E-04			1.90E-03	7.79E-04	1.33E-04	2.30E-03	7.86E-04	1.26E-05
2,2,4-trimethylpentane										
Xylenes										
Inorganic HAPs										
Antimony	4.72E-02			1.04E-03						
Arsenic	0.50			1.10E-02						
Beryllium	0.10			2.17E-03						
Cadmium	2.24E-02	2.66E-04		4.92E-04	6.13E-04	2.52E-04	4.30E-05	7.45E-04		4.08E-06
Chromium	0.43	3.39E-04		9.33E-03	7.80E-04	3.21E-04	5.47E-05	9.48E-04		5.19E-06
Cobalt	0.27			5.86E-03						
Lead	0.63	1.21E-04		1.38E-02	2.79E-04	1.15E-04	1.95E-05	3.39E-04		1.86E-06
Manganese	1.11	9.20E-05	0.21	3.96E-02	2.12E-04	8.71E-05	1.48E-05	2.57E-04		1.41E-06
Mercury	3.25E-03			7.12E-05						
Nickel	0.96	5.09E-04		2.11E-02	1.17E-03	4.81E-04	8.20E-05	1.42E-03	4.86E-04	7.79E-06
Phosphorus			0.25	1.78E-02						
Selenium	0.10			2.10E-03						
Total	**4.17**	**0.46**	**0.46**	**0.12**	**1.05**	**0.43**	**7.37E-02**	**1.28**	**0.43**	**7.00E-03**

Appendix A: Emission Calculations
HAPs Summary

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

Uncontrolled Potential to Emit (tons/yr)											
Emission Unit	EU-4001 Loading Flare Pilot	Loading Racks	Storage Tanks	Residue Solidification units	Cooling Tower	Boiler EU-6000	Emergency Generators	Hydrogen Plant	Wastewater Treatment	Fugitive leaks	Total
Organic HAPs											
Acetaldehyde							1.57E-04				1.57E-04
Acrolein							4.90E-05				4.90E-05
Benzene	2.02E-06	3.15	0.22			6.24E-04	4.82E-03			5.24	8.61
o-cresol		1.37E-03	1.78E-04							0.42	0.42
m+p-cresol		2.58E-04	6.59E-05							0.17	0.17
Cumene											0
Dichlorobenzene	1.16E-06					3.57E-04					2.46E-03
Ethylbenzene											0
Formaldehyde	7.23E-05					2.23E-02	4.90E-04				0.17
n-Hexane	1.73E-03	14.22	0.35			0.54				13.96	32.64
Methanol								28.03			28.03
PAH, total							1.32E-03				1.32E-03
Phenol		5.99E-04	1.53E-04							0.17	0.18
Toluene	3.28E-06	2.64	1.10E-01			1.01E-03	1.75E-03			13.96	16.73
2,2,4-trimethylpentane											0
Xylenes		0.97	0.68				1.20E-03			17.45	19.11
Inorganic HAPs											
Antimony											4.82E-02
Arsenic											0.51
Beryllium											1.01E-01
Cadmium	1.06E-06					3.27E-04					2.52E-02
Chromium	1.35E-06					4.16E-04					0.44
Cobalt											0.27
Lead	4.82E-07					1.49E-04					0.65
Manganese	3.66E-07					1.13E-04					1.37
Mercury											3.32E-03
Nickel	2.02E-06					6.24E-04					0.99
Phosphorus											0.27
Selenium											9.80E-02
Total	**1.82E-03**	**20.99**	**1.36**	**0**	**0**	**0.56**	**9.78E-03**	**28.03**	**6.04**	**51.38**	**116.87**

Appendix A: Emission Calculations
HAPs Summary

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

Potential to Emit After Issuance (tons/yr)										
Emission Unit	Coal Handling Units	Coal Drying Heater EU-1007	Additive Handling	Block 2000 Solids	Feed Heater EU-2001	Treat Gas Heater EU-2002	Vacuum Column Feed Heater EU-2003	Fractionator Heater EU-2004	Sulfur recovery	HP LP SB Flare Pilots
Organic HAPs										
Acetaldehyde										
Acrolein										
Benzene		5.09E-04			1.17E-03	4.81E-04	8.20E-05	1.42E-03	4.86E-04	7.79E-06
o-cresol										
m+p-cresol										
Cumene										
Dichlorobenzene		2.91E-04			6.69E-04	2.75E-04	4.69E-05	8.13E-04		4.45E-06
Ethylbenzene										
Formaldehyde		1.82E-02			4.18E-02	1.72E-02	2.93E-03	5.08E-02	1.73E-02	2.78E-04
n-Hexane		0.44			1.00	0.41	7.03E-02	1.22	0.42	0.01
Methanol										
PAH, total										
Phenol										
Toluene		8.24E-04			1.90E-03	7.79E-04	1.33E-04	2.30E-03	7.86E-04	1.26E-05
2,2,4-trimethylpentane										
Xylenes										
Inorganic HAPs										
Antimony	4.57E-06			2.07E-08						
Arsenic	4.86E-05			2.20E-07						
Beryllium	9.56E-06			4.33E-08						
Cadmium	2.17E-06	2.66E-04		9.82E-09	6.13E-04	2.52E-04	4.30E-05	7.45E-04		4.08E-06
Chromium	4.12E-05	3.39E-04		1.86E-07	7.80E-04	3.21E-04	5.47E-05	9.48E-04		5.19E-06
Cobalt	2.58E-05			1.17E-07						
Lead	6.10E-05	1.21E-04		2.76E-07	2.79E-04	1.15E-04	1.95E-05	3.39E-04		1.86E-06
Manganese	1.08E-04	9.20E-05	2.27E-04	4.20E-05	2.12E-04	8.71E-05	1.48E-05	2.57E-04		1.41E-06
Mercury	3.14E-07			1.42E-09						
Nickel	9.29E-05	5.09E-04		4.20E-07	1.17E-03	4.81E-04	8.20E-05	1.42E-03	4.86E-04	7.79E-06
Phosphorus			2.68E-04	4.90E-05						
Selenium	9.28E-06			4.20E-08						
Total	**4.03E-04**	**0.46**	**4.95E-04**	**9.23E-05**	**1.05**	**0.43**	**7.37E-02**	**1.28**	**0.43**	**0.01**

Appendix A: Emission Calculations
HAPs Summary

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

Potential to Emit After Issuance (tons/yr)											
Emission Unit	EU-4001 Loading Flare Pilot	Loading Racks	Storage Tanks	Residue Solidification units	Cooling Tower	Boiler EU-6000	Emergency Generators	Hydrogen Plant	Wastewater Treatment	Fugitive leaks	Total
Organic HAPs											
Acetaldehyde							1.57E-04				1.57E-04
Acrolein							4.90E-05				4.90E-05
Benzene	2.02E-06	6.29E-02	0.22			6.24E-04	4.82E-03			2.64	2.93
o-cresol		2.75E-05	1.78E-04							0.21	0.21
m+p-cresol		5.17E-06	6.59E-05							8.81E-02	8.82E-02
Cumene											0
Dichlorobenzene	1.16E-06					3.57E-04					2.46E-03
Ethylbenzene											0
Formaldehyde	7.23E-05					2.23E-02	4.90E-04				0.17
n-Hexane	1.73E-03	0.28	0.35			0.54				7.05	11.79
Methanol								28.03			28.03
PAH, total							1.32E-03				1.32E-03
Phenol		1.20E-05	1.53E-04							8.81E-02	8.83E-02
Toluene	3.28E-06	5.29E-02	1.10E-01			1.01E-03	1.75E-03			7.05	7.22
2,2,4-trimethylpentane											0
Xylenes		1.95E-02	0.68				1.20E-03			8.81	9.51
Inorganic HAPs											
Antimony											4.59E-06
Arsenic											4.89E-05
Beryllium											9.61E-06
Cadmium	1.06E-06					3.27E-04					2.25E-03
Chromium	1.35E-06					4.16E-04					2.91E-03
Cobalt											2.60E-05
Lead	4.82E-07					1.49E-04					1.08E-03
Manganese	3.66E-07					1.13E-04					1.15E-03
Mercury											3.15E-07
Nickel	2.02E-06					6.24E-04					4.88E-03
Phosphorus											3.17E-04
Selenium											9.32E-06
Total	**1.82E-03**	**0.42**	**1.36**	**0**	**0**	**0.56**	**9.78E-03**	**28.03**	**0.24**	**25.94**	**60.30**

Appendix A: Emission Calculations
Maximum Sulfur Content

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

Pursuant to 326 IAC 2-2-5 (Air Quality Impact Requirements)

Fuel HHV 1009 MMBtu/MMCF

Unit ID	Description	Model SO_2 Emissions (lb/hr)	Heat Input Capacity (MMBtu/hr)	Maximum Sulfur Content (gr/scf)
EU1007	Coal Milling and Drying Heater	0.1000	55.80	0.0063
EU2001	Feed Heater	0.2381	128.40	0.0065
EU2002	Treat Gas Heater	0.0952	52.80	0.0064
EU2003	Vac Column Feed Heater	0.0159	9.00	0.0062
EU2004	Fractionator Feed Heater	0.2778	156.00	0.0063
EU-3001	TGTU A	12.5081	52.75	
EU-3002	TGTU B	12.5081	52.75	
EU4006	HP Flare	0.0119	7.22	0.0058
EU4005	LP Flare	0.0119	7.22	0.0058
EU4004	SB Flare	0.0690	0.85	0.2853
EU4001	Loading Flare	0.0690	0.22	1.0984
EU6000	Package Boiler	0.1214	68.50	0.0063
EU7001	Hydrogen Reformer 1	0.2730	838.60	0.0011
EU7002	Hydrogen Reformer 2	0.2730	838.60	0.0011

Methodology

Maximum Sulfur Content (gr/scf) = Model SO2 Emissions (lb/hr) x 32 lb (S/lb-mole) / 64 lb (SO2/lb-mole)
x 7,000 (gr/lb) / 1,000,000 (scf/MMCF) x HHV (MMBtu/MMCF)
/ Heat Input Capacity (MMBtu/hr)

Appendix A: Emissions Calculations
Coal Handling Operations with Baghouse

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. Unrestricted PTE

Emissions Unit ID	Process	Coal Throughput (tons/hr)	Emission Factor				Uncontrolled Potential to Emit					
			Source Note	PM	PM_{10}	$PM_{2.5}$	PM		PM_{10}		$PM_{2.5}$	
				(lb/ton)	(lb/ton)	(lb/ton)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
EU-1000	railcar unloading to hopper	5,000	1	0.066	0.066	0.066	330.00	1445.40	330.00	1445.40	330.00	1445.40
	unloading hopper 1 & 2 discharge to feeders	5,000	2	1.40E-04	4.60E-05	1.30E-05	0.70	3.07	0.23	1.01	6.50E-02	0.28
	feeder 1 & 2 discharge to unloading conveyor	5,000	2	1.40E-04	4.60E-05	1.30E-05	0.70	3.07	0.23	1.01	6.50E-02	0.28
EU-1001	unloading conveyor discharge	5,000	2	1.40E-04	4.60E-05	1.30E-05	0.70	3.07	0.23	1.01	6.50E-02	0.28
	transfer station discharge	5,000	2	1.40E-04	4.60E-05	1.30E-05	0.70	3.07	0.23	1.01	6.50E-02	0.28
EU-1006	conveyor 1 discharge to stacker 1 boom	5,000	2	1.40E-04	4.60E-05	1.30E-05	0.70	3.07	0.23	1.01	6.50E-02	0.28
	stacker 1 boom discharge to pile #1A or #1B	5,000	2	1.40E-04	4.60E-05	1.30E-05	0.70	3.07	0.23	1.01	6.50E-02	0.28
	conveyor 2 discharge to stacker 2 boom	5,000	2	1.40E-04	4.60E-05	1.30E-05	0.70	3.07	0.23	1.01	6.50E-02	0.28
	stacker 2 boom discharge to pile #2A or #2B	5,000	2	1.40E-04	4.60E-05	1.30E-05	0.70	3.07	0.23	1.01	6.50E-02	0.28
	reclaimer 1 discharge to conveyor 6	500	2	1.40E-04	4.60E-05	1.30E-05	7.00E-02	0.31	0.02	0.10	6.50E-03	2.85E-02
	reclaimer 2 discharge to conveyor 7	500	2	1.40E-04	4.60E-05	1.30E-05	7.00E-02	0.31	0.02	0.10	6.50E-03	2.85E-02
	conveyor 6 discharge to transfer	500	2	1.40E-04	4.60E-05	1.30E-05	7.00E-02	0.31	0.02	0.10	6.50E-03	2.85E-02
	conveyor 7 discharge to transfer	500	2	1.40E-04	4.60E-05	1.30E-05	7.00E-02	0.31	0.02	0.10	6.50E-03	2.85E-02
	conveyor 9 discharge to transfer	500	2	1.40E-04	4.60E-05	1.30E-05	7.00E-02	0.31	0.02	0.10	6.50E-03	2.85E-02
	reclaim transfer discharge to conveyor 8	500	2	1.40E-04	4.60E-05	1.30E-05	7.00E-02	0.31	0.02	0.10	6.50E-03	2.85E-02
EU-1008	conveyor 8 discharge to mill	500	2	1.40E-04	4.60E-05	1.30E-05	7.00E-02	0.31	0.02	0.10	6.50E-03	2.85E-02
	mill	500	3	1.20E-03	5.40E-04	1.00E-04	0.60	2.63	0.27	1.18	5.00E-02	0.22
	pulverizer	500	4	3.00E-03	1.20E-03	7.00E-05	1.50	6.57	0.60	2.63	3.50E-02	0.15
	dryers	500	5	26.00	3.80	1.10	13000.00	56940.00	1900.00	8322.00	550.00	2409.00
Total								58421.27		9779.97		3857.25

Notes:

1. Bottom dump truck unloading (batch drop), any location, Table 11.9-4, AP-42, 5th ed, 7/98
2. Conveyor transfer point (controlled), SCC 3-05-020-06, Table 11.19.2-2, AP-42 5th ed, 8/04, control a moisture content of 3%
3. Tertiary crushing (controlled), SCC 3-05-020-03, Table 11.19.2-2, AP-42 5th ed, 8/04, control a moisture content of 3%
4. Fines crushing (controlled), SCC 3-05-020-21, Table 11.19.2-2, AP-42 5th ed, 8/04, control a moisture content of 3%
5. Fluidized bed dryer, SCC 3-05-010-01, Table 11.10-1, AP-42, 5th ed, 11/95
6. Control efficiency for partial enclosure conservatively taken as 75%, based on guidance from Fugitive Emissions from Integrated Iron and Steel Plants , EPA 600/2-78-050, March 1978
and Permit to Install 96-12A, Michigan Department of Environmental Quality, December 9, 2014

Methodology
Uncontrolled Potential to Emit (lb/hr) = Coal Throughput (tons/hr) x Emission Factor (lb/ton)
PTE (tons/yr) = PTE (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

Appendix A: Emissions Calculations
Coal Handling Operations with Baghouse

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

2. Bottlenecked Potential to Emit

Emissions Unit ID	Process	Coal Throughput (tons/yr)	Emission Factor				Bottlenecked Potential to Emit Before Controls		
			Source Note	PM (lb/ton)	PM_{10} (lb/ton)	$PM_{2.5}$ (lb/ton)	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)
EU-1000	railcar unloading (Chute 1 & 2)	2,263,248	1	0.066	0.066	0.066	74.69	74.69	74.69
	unloading hopper 1 & 2 discharge to feeders	2,263,248	2	1.40E-04	4.60E-05	1.30E-05	0.16	5.21E-02	1.47E-02
	feeder 1 & 2 discharge to unloading conveyor	2,263,248	2	1.40E-04	4.60E-05	1.30E-05	0.16	5.21E-02	1.47E-02
EU-1001	unloading conveyor discharge	2,263,248	2	1.40E-04	4.60E-05	1.30E-05	0.16	5.21E-02	1.47E-02
	transfer station discharge	2,263,248	2	1.40E-04	4.60E-05	1.30E-05	0.16	5.21E-02	1.47E-02
EU-1006	conveyor 1 discharge to stacker 1 boom[7]	2,263,248	2	1.40E-04	4.60E-05	1.30E-05	0.16	5.21E-02	1.47E-02
	stacker 1 boom discharge to pile #1A or #1B[7]	2,263,248	2	1.40E-04	4.60E-05	1.30E-05	0.16	5.21E-02	1.47E-02
	conveyor 2 discharge to stacker 2 boom	-	2	1.40E-04	4.60E-05	1.30E-05	-	-	-
	stacker 2 boom discharge to pile #2A or #2B	-	2	1.40E-04	4.60E-05	1.30E-05	-	-	-
	reclaimer 1 discharge to conveyor 6[7]	2,263,248	2	1.40E-04	4.60E-05	1.30E-05	0.16	5.21E-02	1.47E-02
	reclaimer 2 discharge to conveyor 7	-	2	1.40E-04	4.60E-05	1.30E-05	-	-	-
	conveyor 6 discharge to transfer[8]	2,263,248	2	1.40E-04	4.60E-05	1.30E-05	0.16	5.21E-02	1.47E-02
	conveyor 7 discharge to transfer	-	2	1.40E-04	4.60E-05	1.30E-05	-	-	-
	conveyor 9 discharge to transfer	-	2	1.40E-04	4.60E-05	1.30E-05	-	-	-
	reclaim transfer discharge to conveyor 8	2,263,248	2	1.40E-04	4.60E-05	1.30E-05	0.16	5.21E-02	1.47E-02
EU-1008	conveyor 8 discharge to mill	2,263,248	2	1.40E-04	4.60E-05	1.30E-05	0.16	5.21E-02	1.47E-02
	mill	2,263,248	3	1.20E-03	5.40E-04	1.00E-04	1.36	0.61	0.11
	pulverizer	2,263,248	4	3.00E-03	1.20E-03	7.00E-05	3.39	1.36	7.92E-02
	dryers	2,263,248	5	26.00	3.80	1.10	29422.22	4300.17	1244.79
Total							29503.25	4377.35	1319.81

Notes:

1. Bottom dump truck unloading (batch drop), any location, Table 11.9-4, AP-42, 5th ed, 7/98

2. Conveyor transfer point (controlled), SCC 3-05-020-06, Table 11.19.2-2, AP-42 5th ed, 8/04, control a moisture content of 3%

3. Tertiary crushing (controlled), SCC 3-05-020-03, Table 11.19.2-2, AP-42 5th ed, 8/04, control a moisture content of 3%

4. Fines crushing (controlled), SCC 3-05-020-21, Table 11.19.2-2, AP-42 5th ed, 8/04, control a moisture content of 3%

5. Fluidized bed dryer, SCC 3-05-010-01, Table 11.10-1, AP-42, 5th ed, 11/95

6. Control efficiency for partial enclosure conservatively taken as 75%, based on guidance from Fugitive Emissions from Integrated Iron and Steel Plants, EPA 600/2-78-050, March 1978 and Permit to Install 96-12A, Michigan Department of Environmental Quality, December 9, 2014

7. Bottlenecked PTE of stacker conveyors and reclaimers is represented in conveyors 2 and 2A and reclaimer 1

8. Bottlenecked PTE of all conveyors into reclaim transfer is represented in conveyor 4

Methodology

Bottlenecked Potential to Emit Before Controls (tons/yr) = Coal Throughput (tons/yr) x Emission Factor (lb/ton) / 2,000 (lb/ton)

Appendix A: Emissions Calculations
Coal Handling Operations with Baghouse

Company Name:	Riverview Energy Corporation
Source Address:	4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.:	147-39554-00065
Reviewer:	Doug Logan
Date:	10/19/2018

3. Hazardous Air Pollutants

HAP	HAP Content[1] (ppm)	Bottlenecked HAP PTE	
		Before Controls (tons/yr)	After Controls (tons/yr)
Antimony	1.60	4.72E-02	4.57E-06
Arsenic	17.04	0.50	4.86E-05
Beryllium	3.35	9.88E-02	9.56E-06
Cadmium	0.76	2.24E-02	2.17E-06
Chromium	14.42	0.43	4.12E-05
Cobalt	9.05	0.27	2.58E-05
Lead	21.36	0.63	6.10E-05
Manganese	37.79	1.11	1.08E-04
Mercury	0.11	3.25E-03	3.14E-07
Nickel	32.55	0.96	9.29E-05
Selenium	3.25	9.59E-02	9.28E-06
Combined HAP		4.17	4.03E-04

Notes:

1. HAP content from Characterization of Indiana's Coal Resource: Availability of the Reserves, Physical and Chemical Properties of the Coal, and Present and Potential Uses , Indiana Geolocial Survey - File Study 04-02 July 2004.

Methodology

HAP PTE Before Controls (tons/yr) = Bottlenecked PM PTE Before Controls (tons/yr) x HAP Content (ppm) / 1,000,000
HAP PTE After Controls (tons/yr) = PM PTE After Controls (tons/yr) x HAP Content (ppm) / 1,000,000
Fugitive HAP PTE (tons/yr) = Bottlenecked Fugitive PM PTE (tons/yr) x HAP Content (ppm) / 1,000,000

4. Potential to Emit After Issuance

		Air Flow Rate (dscfm)	Pollutant		
			PM	PM_{10}	direct $PM_{2.5}$
EU-1000	Emissions Limitation[1] (gr/dscf)	6591	0.0022	0.0022	0.0022
	Potential to Emit After Issuance (lb/hr)		0.12	0.12	0.12
	Potential to Emit After Issuance (tons/yr)		0.54	0.54	0.54
EU-1001	Emissions Limitation[1] (gr/dscf)	9276	0.002	0.002	0.002
	Potential to Emit After Issuance (lb/hr)		0.16	0.16	0.16
	Potential to Emit After Issuance (tons/yr)		0.70	0.70	0.70
EU-1006	Emissions Limitation[1] (gr/dscf)	6184	0.002	0.002	0.002
	Potential to Emit After Issuance (lb/hr)		0.11	0.11	0.11
	Potential to Emit After Issuance (tons/yr)		0.46	0.46	0.46
EU-1008	Emissions Limitation[1] (gr/dscf)	15308	0.002	0.002	0.002
	Potential to Emit After Issuance (lb/hr)		0.26	0.26	0.26
	Potential to Emit After Issuance (tons/yr)		1.15	1.15	1.15
Total			**2.85**	**2.85**	**2.85**

Notes:

Methodology

PTE After Issuance (lb/hr) = Air Flow Rate (dscfm) x Emissions Limitation (gr/dscf) x 60 (min/hr) / 7,000 (gr/lb)
PTE After Issuance (tons/yr) = PTE After Issuance (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
Coal Dryer Heater EU-1007

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

Heat Input Capacity MMBtu/hr	HHV mmBtu mmscf	Potential Throughput MMCF/yr
55.8	1009	484.4

1. Uncontrolled Potential to Emit

	Pollutant						
	PM^1	PM$_{10}^{1}$	direct PM$_{2.5}^{1}$	SO$_2$	NOx	VOC	CO
Emission Factor in lb/MMCF (AP-42)	1.9	7.6	7.6	-	-	5.5	-
Emission Factor in lb/MMCF^2	-	-	-	1.797	-	-	-
Emission Factor in lb/MMBtu^3 (Mfr)	-	-	-	-	0.04	-	0.036
Potential Emission in tons/yr	0.46	1.84	1.84	0.44	9.78	1.33	8.80

Notes:
1. PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
2. Worst-case factor provided by the source based on local natural gas composition and use of fractionator tower overhead in fuel gas supply, subject to testing.
3. Emission factors provided by the burner manufacturer, subject to testing.

Methodology
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	n-Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	5.09E-04	2.91E-04	1.82E-02	0.44	8.24E-04	**0.46**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	1.21E-04	2.66E-04	3.39E-04	9.20E-05	5.09E-04	**1.33E-03**

Total HAPs	**0.46**
Worst HAP	**0.44**

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

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	0.64
Potential Emission in tons/yr	29,067	0.56	0.16
Summed Potential Emissions in tons/yr	29,068		
CO2e Total in tons/yr	29,127		

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

2. Potential to Emit After Issuance

	Pollutant							
	PM	PM$_{10}$	direct PM$_{2.5}$	SO$_2$	NOx	VOC	CO	CO$_2$e
Emission Limit^1 in lb/MMBtu	0.0019	0.0075	0.0075	-	0.030	0.0054	0.0365	-
Maximum Emission Limit^2 in gr S/scf	-	-	-	0.0062	-	-	-	-
Annual Emission Limit^3 in gr S/scf	-	-	-	0.005	-	-	-	-
Compliance determination coefficient (ton CO2e/MMCF)								60.12
PTE After Issuance in lb/hr	0.11	0.42	0.42	0.10	1.67	0.30	2.04	-
PTE After Issuance in tons/yr	0.46	1.83	1.83	0.35	7.33	1.32	8.92	29,127

Notes:
1. BACT specifications
2. Maximum
3. Twelve (12) month average

Methodology
Compliance determination coefficient (ton CO2e/MMCF) = CO$_2$e Total (tons/yr) / Potential Throughput (MMCF/yr)
PTE After Issuance (lb/hr) = Heat Input Capacity (MMBtu/hr) / HHV (MMBtu/MMCF) x 1,000,000 (SCF/MMCF) x Maximum Emission Limit (gr/scf) / 7,000 (gr/lb) x 64 (lb SO$_2$/lb-mole) / 32 (lb S/lb-mole) *SO$_2$*
PTE After Issuance (lb/hr) = Emission Limit (lb/MMBtu) x Heat Input Capacity (MMBtu/hr) *all others*
PTE After Issuance (tons/yr) = Heat Input Capacity (MMBtu/hr) / HHV (MMBtu/MMCF) x 1,000,000 (SCF/MMCF) x Annual Emission Limit (gr/scf) / 7,000 (gr/lb) x 64 (lb SO$_2$/lb-mole) / 32 (lb S/lb-mole)
x 8,760 (hr/yr) / 2,000 (lb/ton) *SO$_2$*
PTE After Issuance (tons/yr) = PTE After Issuance (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton) *all others*

Appendix A: Emissions Calculations
Additive Handling Emissions

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. Silo Loading

A. Unrestricted Potential to Emit

Description	Unit ID	Control Device ID	Silo Throughput[1]	Uncontrolled					
				Emission Factor[2]		Potential to Emit			
				PM	PM10 = PM2.5	PM	PM10 = PM2.5	PM	PM10 = PM2.5
			(tons/hr)	(lb/ton)	(lb/ton)	(lb/hr)	(lb/hr)	(tons/yr)	(tons/yr)
Coarse additive silo	T33	EU-1501	20.00	0.73	0.46	14.60	9.20	63.95	40.30
Fine additive silo	T34	EU-1502	20.00	0.73	0.46	14.60	9.20	63.95	40.30
Sodium sulfide silo	T35	EU-1503	10.00	0.73	0.46	7.30	4.60	31.97	20.15

Methodology
Potential to Emit (lb/hr) = Silo Throughput (tons/hr) x Emission Factor (lb/ton)
Potential to Emit (tons/yr) = Potential to Emit (lb/hr) x 8,760 (hrs/yr) / 2,000 (lb/ton)

B. Bottlenecked Potential to Emit

Description	Unit ID	Control Device ID	Bottlenecked Additive Throughput[3]	Uncontrolled			
				Emission Factor[2]		Potential to Emit	
				PM	PM10 = PM2.5	PM	PM10 = PM2.5
			(tons/yr)	(lb/ton)	(lb/ton)	(tons/yr)	(tons/yr)
Coarse additive silo	T33	EU-1501	28776.60	0.73	0.46	10.50	6.62
Fine additive silo	T34	EU-1502	28776.60	0.73	0.46	10.50	6.62
Sodium sulfide silo	T35	EU-1503	674.52	0.73	0.46	0.25	0.16
Total						**21.25**	**13.39**

Notes to section 1A & B:
1. Silo Throughput is the rate of unloading delivery trucks or railcars.
2. Emission factors from AP-42, Chapter 11.12 Concrete Batching, Table 11.12-2 (updated June 2006) SCC 3-05-011-07 (cement unloading to elevated storage silo)
Emission factor unit is pounds per ton of material loaded. PM2.5 assumed equal to PM10 because AP-42 does not have emission factors for PM2.5.
3. Bottlenecked throughput based on bottlenecked production capacity.

Methodology
Bottlenecked Throughput (tons/yr) = Bottlenecked mixer capacity (tons/hr) x 8,760 hr/yr x weight fraction of cement in mix
Potential to Emit (tons/yr) = Bottlenecked Throughput (tons/yr) x Emission Factor (lb/ton) / 2,000 (lb/ton)

C. Hazardous Air Pollutants

Description	Unit ID	Control Device ID	HAP Content		Unrestricted PTE (tons/yr)			
			Manganese compounds (as Mn) (Wt %)	Phosphorus pentoxide (as P) (Wt %)	PM	Manganese	Phosphorus	Combined HAP
Coarse additive silo	T33	EU-1501	0.11%	0.13%	63.95	0.07	0.08	0.15
Fine additive silo	T34	EU-1502	0.11%	0.13%	63.95	0.07	0.08	0.15
Total						**0.14**	**0.17**	**0.31**

Description		Bottlenecked PTE (tons/yr)			
		PM	Manganese	Phosphorus	Combined HAP
Coarse additive silo		10.50	1.16E-02	1.37E-02	2.52E-02
Fine additive silo		10.50	1.16E-02	1.37E-02	2.52E-02
Total			**2.31E-02**	**2.73E-02**	**5.04E-02**

Methodology
Unrestricted HAP PTE (tons/yr) = Unrestricted PM PTE (tons/yr, *Section 1A*) x HAP Content (Wt %)/100
Bottlenecked HAP PTE (tons/yr) = Bottlenecked PM PTE (tons/yr, *Section 1B*) x HAP Content (wt %)/100

2. Size Reduction

A. Particulate

Description	Unit ID	Control Device ID	Process Throughput	Uncontrolled								
				Emission Factor[1]			Potential to Emit					
				PM	PM10	PM2.5	PM	PM10	PM2.5	PM	PM10	PM2.5
			(tons/hr)	(lb/ton)	(lb/ton)	(lb/ton)	(lb/hr)	(lb/hr)	(lb/hr)	(tons/yr)	(tons/yr)	(tons/yr)
Fine additive production system		EU-1504	3.28	12	12	12	39.42	39.42	39.42	172.65	172.65	172.65
Total										**172.65**	**172.65**	**172.65**

Description	Unit ID	Control Device ID	Process Throughput	After Controls								
				Emission Factor[2]			Potential to Emit					
				PM	PM10	PM2.5	PM	PM10	PM2.5	PM	PM10	PM2.5
			(tons/hr)	(lb/ton)	(lb/ton)	(lb/ton)	(lb/hr)	(lb/hr)	(lb/hr)	(tons/yr)	(tons/yr)	(tons/yr)
Fine additive production system		EU-1504	3.28	0.12	0.12	0.12	0.39	0.39	0.39	1.73	1.73	1.73
Total										**1.73**	**1.73**	**1.73**

Notes:
Additive (coarse or fine) is red mud, a byproduct of aluminum production. Considered as a finely ground material held in larger particles by physical bonding.
1. Emission factor for natural clay crushing, screening, and storage (SCC 3-05-009-04), Table 11.8-2, AP-42 5th ed., February 1972
2. Emission factor for comminution - raw material crushing and screening line with fabric filter (SCC 3-05-008-02), Table 11.7-1, AP-42, 5th ed., July 1996

Methodology
Uncontrolled PTE (lb/hr) = Process Throughput (tons/hr) x Uncontrolled Emission Factor (lb/ton)
After Controls PTE (lb/hr) = Process Throughput (tons/hr) x After Controls Emission Factor (lb/ton)
PTE (tons/yr) = PTE (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

Appendix A: Emissions Calculations
Additive Handling Emissions

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

B. Hazardous Air Pollutants

Description	Unit ID	Control Device ID	HAP Content		Uncontrolled PTE (tons/yr)			
			Manganese compounds (as Mn) (Wt %)	Phosphorus pentoxide (as P) (Wt %)	PM	Manganese	Phosphorus	Combined HAP
Fine additive production system		EU-1504	0.11%	0.13%	172.65	0.19	0.22	0.41

Description		After Controls PTE (tons/yr)			
		PM	Manganese	Phosphorus	Combined HAP
Fine additive production system		1.73	1.90E-03	2.24E-03	4.14E-03

Methodology
Uncontrolled HAP PTE (tons/yr) = Uncontrolled PM PTE (tons/yr, *Section 2A*) x HAP Content (Wt %)/100
After Controls HAP PTE (tons/yr) = After Controls PM PTE (tons/yr, *Section 2A*) x HAP Content (wt %)/100

3. Total of All Additive Handling Operations

	Potential to Emit (tons/yr)					
	PM	PM10	PM2.5	Manganese	Phosphorus	Total HAP
Uncontrolled	193.91	186.04	186.04	0.21	0.25	0.46
After Controls	#REF!	#REF!	#REF!	0.03	0.03	0.05

4. Potential to Emit After Issuance

	Unit	Air Flow Rate (dscfm)	Pollutant					
			PM	PM$_{10}$	direct PM$_{2.5}$	Manganese	Phosphorus	Combined HAP
Emissions Limitation[1] (gr/dscf)	EU-1501	942	0.002	0.002	0.002			
Potential to Emit After Issuance (lb/hr)			0.016	0.016	0.016			
Potential to Emit After Issuance (tons/yr)			0.07	0.07	0.07	7.78E-05	9.19E-05	1.70E-04
Emissions Limitation[1] (gr/dscf)	EU-1502	1041	0.002	0.002	0.002			
Potential to Emit After Issuance (lb/hr)			0.018	0.018	0.018			
Potential to Emit After Issuance (tons/yr)			0.08	0.08	0.08	8.60E-05	1.02E-04	1.88E-04
Emissions Limitation[1] (gr/dscf)	EU-1503	765	0.002	0.002	0.002			
Potential to Emit After Issuance (lb/hr)			0.013	0.013	0.013			
Potential to Emit After Issuance (tons/yr)			0.06	0.06	0.06	6.32E-05	7.47E-05	1.38E-04
Emissions Limitation[1] (gr/dscf)	EU-1504	260	0.002	0.002	0.002			
Potential to Emit After Issuance (lb/hr)			0.004	0.004	0.004			
Potential to Emit After Issuance (tons/yr)			0.02	0.02	0.02			
Total			**0.23**	**0.23**	**0.23**	**2.27E-04**	**2.68E-04**	**4.95E-04**

Notes:
1. BACT specifications

Methodology
PTE After Issuance (lb/hr) = Air Flow Rate (dscfm) x Emissions Limitation (gr/dscf) x 60 (min/hr) / 7,000 (gr/lb)
PTE After Issuance (tons/yr) = PTE After Issuance (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

Appendix A: Emissions Calculations
Block 2000 Solids Handling

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. Unrestricted PTE

A. Criteria Pollutants

Emissions Unit ID	Process	Throughput	Emission Factor[1]			Uncontrolled Potential to Emit					
			PM	PM_{10}	$PM_{2.5}$	PM		PM_{10}		$PM_{2.5}$	
		(tons/hr)	(lb/ton)	(lb/ton)	(lb/ton)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
EU-2005	enclosed screw conveyor to Block 2000 feed premix drum	500	0.572	0.156	0.156	286.00	1252.68	78.00	341.64	78.00	341.64
EU-2006	coarse additive screw conveyor	2.20	0.572	0.156	0.156	1.26	5.51	0.34	1.50	0.34	1.50
EU-2007	fine additive handling system	3.28	0.572	0.156	0.156	1.88	8.22	0.51	2.24	0.51	2.24
EU-2008	sodium sulfide conveyor	0.08	0.572	0.156	0.156	4.41E-02	0.19	0.01	0.05	0.01	0.05
Total							**1266.60**		**345.44**		**345.44**

Notes:

1. Emission factors: mixer loading (central mix) (SCC 3-05-011-09), Table 11.12-2, AP-42 5th ed., 6/06

Methodology

Uncontrolled Potential to Emit (lb/hr) = Throughput (tons/hr) x Emission Factor (lb/ton)
PTE (tons/yr) = PTE (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

B. Hazardous Air Pollutants

HAP	Coal HAP Content[1] (ppm)	Additive HAP Content[2] (weight %)	Uncontrolled PTE (tons/yr)		
			Coal	Additive	Combined
Antimony	1.60		2.00E-03		2.00E-03
Arsenic	17.04		2.13E-02		2.13E-02
Beryllium	3.35		4.20E-03		4.20E-03
Cadmium	0.76		9.52E-04		9.52E-04
Chromium	14.42		1.81E-02		1.81E-02
Cobalt	9.05		1.13E-02		1.13E-02
Lead	21.36		2.68E-02		2.68E-02
Manganese	37.79	0.11%	4.73E-02	1.51E-02	6.24E-02
Mercury	0.11		1.38E-04		1.38E-04
Nickel	32.55		4.08E-02		4.08E-02
Phosphorus	0	0.13%	0	1.78E-02	1.78E-02
Selenium	3.25		4.07E-03		4.07E-03
Combined HAP					0.21

Notes:

1. HAP content from <u>Characterization of Indiana's Coal Resource: Availability of the Reserves, Physical and Chemical Properties of the Coal, and Present and Potential Uses</u>, Indiana Geolocial Survey - File Study 04-02 July 2004.

2. Additive analysis provided by the source

Methodology

Uncontrolled HAP PTE (tons/yr) = Uncontrolled PM PTE (EU-2005) (tons/yr) x Coal HAP Content (ppm) / 1,000,000 *Coal*
Uncontrolled HAP PTE (tons/yr) = Uncontrolled PM PTE (EU-2006 + EU-2007) (tons/yr) x Additive HAP Content (%) / 100 *Additives*

2. Bottlenecked PTE

A. Criteria Pollutants

Emissions Unit ID	Process	Bottlenecked Throughput (tons/yr)	Emission Factor[1]			Bottlenecked Potential to Emit					
			PM	PM_{10}	$PM_{2.5}$	PM		PM_{10}		$PM_{2.5}$	
			(lb/ton)	(lb/ton)	(lb/ton)		(tons/yr)		(tons/yr)		(tons/yr)
EU-2005	enclosed screw conveyor to Block 2000 feed premix drum	2,263,248	0.572	0.156	0.156		647.29		176.53		176.53
EU-2006	coarse additive screw conveyor	19,272	0.572	0.156	0.156		5.51		1.50		1.50
EU-2007	fine additive handling system	28,733	0.572	0.156	0.156		8.22		2.24		2.24
EU-2008	sodium sulfide conveyor	676	0.572	0.156	0.156		0.19		0.05		0.05
Total							**661.21**		**180.33**		**180.33**

Notes:

1. Emission factors: mixer loading (central mix) (SCC 3-05-011-09), Table 11.12-2, AP-42 5th ed., 6/06

Methodology

Bottlenecked Potential to Emit (tons/yr) = Bottlenecked Throughput (tons/yr) x Emission Factor (lb/ton) / 2,000 (lb/ton)

Appendix A: Emissions Calculations
Block 2000 Solids Handling

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

B. Hazardous Air Pollutants

HAP	Coal HAP Content[1] (ppm)	Additive HAP Content[2] (weight %)	Bottlenecked PTE (tons/yr)		
			Coal	Additive	Combined
Antimony	1.60		1.04E-03		1.04E-03
Arsenic	17.04		1.10E-02		1.10E-02
Beryllium	3.35		2.17E-03		2.17E-03
Cadmium	0.76		4.92E-04		4.92E-04
Chromium	14.42		9.33E-03		9.33E-03
Cobalt	9.05		5.86E-03		5.86E-03
Lead	21.36		1.38E-02		1.38E-02
Manganese	37.79	0.11%	2.45E-02	1.51E-02	3.96E-02
Mercury	0.11		7.12E-05		7.12E-05
Nickel	32.55		2.11E-02		2.11E-02
Phosphorus	0	0.13%	0	1.78E-02	1.78E-02
Selenium	3.25		2.10E-03		2.10E-03
Combined HAP					0.12

Notes:
1. HAP content from *<u>Characterization of Indiana's Coal Resource: Availability of the Reserves, Physical and Chemical Properties of the Coal, and Present and Potential Uses</u>, Indiana Geolocial Survey - File Study 04-02 July 2004.*
2. Additive analysis provided by the source

Methodology
Bottlenecked HAP PTE (tons/yr) = Bottlenecked PM PTE (EU-2005) (tons/yr) x Coal HAP Content (ppm) / 1,000,000 *Coal*
Bottlenecked HAP PTE (tons/yr) = Bottlenecked PM PTE (EU-2006 + EU-2007) (tons/yr) x Additive HAP Content (%) / 100 *Additives*

<u>3. Potential to Emit After Issuance</u>

A. Criteria Pollutants

	Unit	Air Flow Rate (dscfm)	Pollutant		
			PM	PM_{10}	direct $PM_{2.5}$
Emissions Limitation[1] (gr/dscf)	EU-2005	172	0.002	0.002	0.002
Potential to Emit After Issuance (lb/hr)			0.003	0.003	0.003
Potential to Emit After Issuance (tons/yr)			0.01	0.01	0.01
Emissions Limitation[1] (gr/dscf)	EU-2006	242	0.002	0.002	0.002
Potential to Emit After Issuance (lb/hr)			0.004	0.004	0.004
Potential to Emit After Issuance (tons/yr)			0.02	0.02	0.02
Emissions Limitation[1] (gr/dscf)	EU-2007	260	0.002	0.002	0.002
Potential to Emit After Issuance (lb/hr)			0.004	0.004	0.004
Potential to Emit After Issuance (tons/yr)			0.02	0.02	0.02
Emissions Limitation[1] (gr/dscf)	EU-2008	48	0.002	0.002	0.002
Potential to Emit After Issuance (lb/hr)			0.001	0.001	0.001
Potential to Emit After Issuance (tons/yr)			3.60E-03	3.60E-03	3.60E-03
Total			**0.05**	**0.05**	**0.05**

Notes:
1. BACT specifications

Methodology
PTE After Issuance (lb/hr) = Air Flow Rate (dscfm) x Emissions Limitation (gr/dscf) x 60 (min/hr) / 7,000 (gr/lb)
PTE After Issuance (tons/yr) = PTE After Issuance (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

B. Hazardous Air Pollutants

HAP	Coal HAP Content[1] (ppm)	Additive HAP Content[2] (weight %)	PTE After Issuance (tons/yr)		
			Coal	Additive	Combined
Antimony	1.60		2.07E-08		2.07E-08
Arsenic	17.04		2.20E-07		2.20E-07
Beryllium	3.35		4.33E-08		4.33E-08
Cadmium	0.76		9.82E-09		9.82E-09
Chromium	14.42		1.86E-07		1.86E-07
Cobalt	9.05		1.17E-07		1.17E-07
Lead	21.36		2.76E-07		2.76E-07
Manganese	37.79	0.11%	4.88E-07	4.15E-05	4.20E-05
Mercury	0.11		1.42E-09		1.42E-09
Nickel	32.55		4.20E-07		4.20E-07
Phosphorus	0	0.13%	0	4.90E-05	4.90E-05
Selenium	3.25		4.20E-08		4.20E-08
Combined HAP					9.23E-05

Notes:
1. HAP content from *<u>Characterization of Indiana's Coal Resource: Availability of the Reserves, Physical and Chemical Properties of the Coal, and Present and Potential Uses</u>, Indiana Geolocial Survey - File Study 04-02 July 2004.*
2. Additive analysis provided by the source

Methodology
HAP PTE After Issuance (tons/yr) = PM PTE After Issuance (EU-2005) (tons/yr) x Coal HAP Content (ppm) / 1,000,000 *Coal*
HAP PTE After Issuance (tons/yr) = PM PTE After Issuance (EU-2006 + EU-2007) (tons/yr) x Additive HAP Content (%) / 100 *Additives*

Appendix A: Emission Calculations
Natural Gas Combustion Only
MMBTU/HR >100
Feed Heater and Fractionation Heater

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

		Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
Feed heater	EU-2001	128.4	1009	1114.8
Fractionator heater	EU-2004	156.0	1009	1354.4

1. Uncontrolled Potential to Emit

	Pollutant						
	PM[1]	PM_{10}[1]	direct $PM_{2.5}$[1]	SO_2	NOx	VOC	CO
Emission Factor in lb/MMCF (AP-42)	1.9	7.6	7.6	-	-	5.5	-
Emission Factor in lb/MMCF[2]	-	-	-	1.797	-	-	-
Emission Factor in lb/MMBtu[3] (Mfr)	-	-	-	-	0.04	-	0.036
EU-2001 PTE in tons/yr	1.06	4.24	4.24	1.00	22.50	3.07	20.25
EU-2004 PTE in tons/yr	1.29	5.15	5.15	1.22	27.33	3.72	24.60

Notes:
1. PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
2. Worst-case factor provided by the source based on local natural gas composition and use of fractionator tower overhead in fuel gas supply, subject to testing.
3. Emission factors provided by the burner manufacturer, subject to testing.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, and 1.4-3, SCC #1-01-006-01, 1-01-006-04 (AP-42 Supplement D 3/98)
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760 hr/yr x 1 ton/2,000 lb

Hazardous Air Pollutants (HAPs)

	HAPs - Organics				
	Benzene	Dichlorobenzene	Formaldehyde	n-Hexane	Toluene
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
EU-2001 PTE in tons/yr	1.17E-03	6.69E-04	4.18E-02	1.00	1.90E-03
EU-2004 PTE in tons/yr	1.42E-03	8.13E-04	5.08E-02	1.22	2.30E-03

	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
EU-2001 PTE in tons/yr	2.79E-04	6.13E-04	7.80E-04	2.12E-04	1.17E-03
EU-2004 PTE in tons/yr	3.39E-04	7.45E-04	9.48E-04	2.57E-04	1.42E-03

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

Total			
	EU-2001	1.05	ton/yr
	EU-2004	1.28	ton/yr

Greenhouse Gases (GHGs)

	EU-2001			EU-2004		
	Greenhouse Gas			Greenhouse Gas		
	CO2	CH4	N2O	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	0.64	120,000	2.3	0.64
Potential Emission in tons/yr	66,885	1.3	0.4	81,262	1.6	0.4
Summed Potential Emissions in tons/yr	66,887			81,264		
CO2e Total in tons/yr	67,023			81,430		

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

2. Potential to Emit After Issuance

	Pollutant							
	PM	PM_{10}	direct $PM_{2.5}$	SO_2	NOx	VOC	CO	CO_2e
Emission Limit[1] in lb/MMBtu	0.0019	0.0075	0.0075	-	0.030	0.0054	0.0365	-
Maximum Emission Limit[2] in gr S/scf	-	-	-	0.0062	-	-	-	-
Annual Emission Limit[3] in gr S/scf	-	-	-	0.005	-	-	-	-
Compliance determination coefficient (ton CO2e/MMCF)								60.12
EU-2001 PTE After Issuance in lb/hr	0.24	0.96	0.96	0.23	3.85	0.69	4.69	-
EU-2001 PTE After Issuance in tons/yr	1.07	4.22	4.22	0.80	16.87	3.04	20.53	67,023
EU-2004 PTE After Issuance in lb/hr	0.30	1.17	1.17	0.27	4.68	0.84	5.69	-
EU-2004 PTE After Issuance in tons/yr	1.30	5.12	5.12	0.97	20.50	3.69	24.94	81,430

Notes:
1. BACT specifications
2. Maximum
3. Twelve (12) month average

Methodology
Compliance determination coefficient (ton CO2e/MMCF) = CO_2e Total (tons/yr) / Potential Throughput (MMCF/yr)
PTE After Issuance (lb/hr) = Heat Input Capacity (MMBtu/hr) / HHV (MMBtu/MMCF) x 1,000,000 (SCF/MMCF) x Maximum Emission Limit (gr/scf) / 7,000 (gr/lb) x 64 (lb SO_2/lb-mole) / 32 (lb S/lb-mole) *SO_2*
PTE After Issuance (lb/hr) = Emission Limit (lb/MMBtu) x Heat Input Capacity (MMBtu/hr) *all others*
PTE After Issuance (tons/yr) = Heat Input Capacity (MMBtu/hr) / HHV (MMBtu/MMCF) x 1,000,000 (SCF/MMCF) x Annual Emission Limit (gr/scf) / 7,000 (gr/lb) x 64 (lb SO_2/lb-mole) / 32 (lb S/lb-mole) x 8,760 (hr/yr) / 2,000 (lb/ton) *SO_2*
PTE After Issuance (tons/yr) = PTE After Issuance (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton) *all others*

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
Treat Gas Heater (EU-2002) and Vacuum Column Feed Heater (EU-2003)

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

		Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
Treat gas heater	EU-2002	52.8	1009	458.4
Vacuum column feed heater	EU-2003	9.0	1009	78.1

1. Uncontrolled Potential to Emit

	Pollutant						
	PM[1]	PM_{10}[1]	direct $PM_{2.5}$[1]	SO_2	NOx	VOC	CO
Emission Factor in lb/MMCF (AP-42)	1.9	7.6	7.6	-	-	5.5	-
Emission Factor in lb/MMCF[2]	-	-	-	1.797	-	-	-
Emission Factor in lb/MMBtu[3] (Mfr)	-	-	-	-	0.04	-	0.036
EU-2003 PTE in tons/yr	0.44	1.74	1.74	0.41	9.25	1.26	8.33
EU-2003 PTE in tons/yr	0.07	0.30	0.30	0.07	1.58	0.21	1.42

Notes:
1. PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
2. Worst-case factor provided by the source based on local natural gas composition and use of fractionator tower overhead in fuel gas supply, subject to testing.
3. Emission factors provided by the burner manufacturer, subject to testing.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760 hr/yr x 1 ton/2,000 lb

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	n-Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03	
EU-2002 PTE in tons/yr	4.81E-04	2.75E-04	1.72E-02	0.41	7.79E-04	**0.43**
EU-2003 PTE in tons/yr	8.20E-05	4.69E-05	2.93E-03	7.03E-02	1.33E-04	**7.35E-02**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
EU-2002 PTE in tons/yr	1.15E-04	2.52E-04	3.21E-04	8.71E-05	4.81E-04	**1.26E-03**
EU-2003 PTE in tons/yr	1.95E-05	4.30E-05	5.47E-05	1.48E-05	8.20E-05	**2.14E-04**

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

Total			
	EU-2002	0.43	ton/yr
	EU-2003	7.37E-02	ton/yr

Greenhouse Gases (GHGs)

	EU-2002			EU-2003		
	Greenhouse Gas			Greenhouse Gas		
	CO2	CH4	N2O	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	0.64	120,000	2.3	0.64
Potential Emission in tons/yr	27,504	0.53	0.15	4,688	0.1	0.0
Summed Potential Emissions in tons/yr	27,505			4,688		
CO2e Total in tons/yr	27,561			4,698		

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

2. Potential to Emit After Issuance

	Pollutant							
	PM	PM_{10}	direct $PM_{2.5}$	SO_2	NOx	VOC	CO	CO_2e
Emission Limit[1] in lb/MMBtu	0.0019	0.0075	0.0075	-	0.030	0.0054	0.0365	-
Maximum Emission Limit[2] in gr S/scf	-	-	-	0.0062	-	-	-	-
Annual Emission Limit[3] in gr S/scf	-	-	-	0.005	-	-	-	-
Compliance determination coefficient (ton CO2e/MMCF)								60.12
EU-2002 PTE After Issuance in lb/hr	0.10	0.40	0.40	0.09	1.58	0.29	1.93	-
EU-2002 PTE After Issuance in tons/yr	0.44	1.73	1.73	0.33	6.94	1.25	8.44	27,561
EU-2003 PTE After Issuance in lb/hr	1.71E-02	6.75E-02	6.75E-02	0.02	0.27	0.05	0.33	-
EU-2003 PTE After Issuance in tons/yr	0.07	0.30	0.30	0.06	1.18	0.21	1.44	4,698

Notes:
1. BACT specifications
2. Maximum
3. Twelve (12) month average

Methodology
Compliance determination coefficient (ton CO2e/MMCF) = CO_2e Total (tons/yr) / Potential Throughput (MMCF/yr)
PTE After Issuance (lb/hr) = Heat Input Capacity (MMBtu/hr) / HHV (MMBtu/MMCF) x 1,000,000 (SCF/MMCF) x Maximum Emission Limit (gr/scf) / 7,000 (gr/lb) x 64 (lb SO_2/lb-mole) / 32 (lb S/lb-mole) *SO_2*
PTE After Issuance (lb/hr) = Emission Limit (lb/MMBtu) x Heat Input Capacity (MMBtu/hr) *all others*
PTE After Issuance (tons/yr) = Heat Input Capacity (MMBtu/hr) / HHV (MMBtu/MMCF) x 1,000,000 (SCF/MMCF) x Annual Emission Limit (gr/scf) / 7,000 (gr/lb) x 64 (lb SO_2/lb-mole) / 32 (lb S/lb-mole) x 8,760 (hr/yr) / 2,000 (lb/ton) *SO_2*
PTE After Issuance (tons/yr) = PTE After Issuance (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton) *all others*

Appendix A: Emission Calculations
Tail Gas Treatment Units

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

<u>Process Specifications</u>

Coal usage: 258 tph at 8.00% moisture and 6.67% ash = 220.46 tph, moisture and ash free
sulfur content: 3.30% by weight (moisture and ash free)
from S. Lang, KBR, by email 3/29/2018, 11:39AM

Potential sulfur productior 220.46 tons coal/hr x 3.30% sulfur x 8760 hr/yr = 63,731 tons of sulfur/year

	Heat Input Capacity (MMBtu/hr)		Sulfur Production Rate (tons/yr)	
	Maximum	Bottlenecked	Maximum	Bottlenecked
TGTUA (EU-3001)	52.75	75.35	44,611	63,731
TGTUB (EU-3002)	52.75		44,611	

Exhaust flow rate (each): 25,169 acfm @ 549.3 K = 989 °R *Bottlenecked case, each SRU handling a nominal 50% of VCC capacity*
35,956 acfm *Maximum for each SRU, 70% of VCC capacity*
(based on modeling parameters provided by the source, 70% of VCC capacity, including excess oxygen, nitrogen, and trace gases)

Site elevation (ASL): 148 m , thus nominal site atmospheric pressure = 0.983 atm
Interpolated from Table 3-214, <u>Perry's Chemical Engineers' Handbook, 6th ed.</u>

Exhaust moisture correction:
4.69 (lb mole H_2O/min), *each SRU, bottlenecked, 50% of VCC capacity*
6.57 (lb mole H_2O/min), *SRU maximum, 70% of VCC capacity*
determined by the source from design material balance, includes moisture from combustion of H_2S and saturation of inlet streams after amine and caustic scrubbers

and the exhaust molar flow rate (dry) is:
Bottlenecked condition, 50% of VCC capacity.
25,169 (acfm) x 0.983 (atm) / [989 (°R) x 0.7302 (atm ft^3/lb mole °R)] - 4.69 (lb mole H_2O/min) = 29.59 (lb mole/min)
correcting to 0% O_2 based on design oxygen content in the exhaust: 3.29% O_2 28.62 (lb mole/min @ 0% O_2)
SRU (each) maximum, 70% of VCC capacity
35,956 (acfm) x 0.983 (atm) / [989 (°R) x 0.7302 (atm ft^3/lb mole °R)] - 6.57 (lb mole H_2O/min) = 42.40 (lb mole/min)
correcting to 0% O_2 based on design oxygen content in the exhaust: 3.29% O_2 41.01 (lb mole/min @ 0% O_2)

Methodology
Exhaust molar flow rate (lb-mole/min @ 0% O_2) = Exhaust molar flow rate (lb-mole/min) x [1 - %O_2/100]

<u>1. Uncontrolled Potential to Emit</u>

	Pollutant						
	PM	PM_{10}	direct $PM_{2.5}$	SO_2	NOx	VOC	CO
Emission Factor (lb/ton)[1]	-	-	-	4.0	-	-	-
Emission Factor (lb/MMBtu)[2]	-	-	-	-	0.100	0.0014	0.710
Emission Factor (lb/MMBtu)[3]	0.0019	0.0075	0.0075	-	-	-	-
Bottlenecked PTE (tons/yr)	0.61	2.46	2.46	127.46	33.00	0.46	234.32
Uncontrolled Bottlenecked PTE (tons/yr)[4]				127,461			

Notes:
1. Table 8.13-1 (SCC 3-01-032-04, scrubbing type of tail gas treatment), AP-42, 5th ed., April 2015
2. Table 8.13-2 (SCC 3-01-032), AP-42, 5th ed., April 2015
3. Scaled from Table 1.4-2, AP-42, 5th ed., July 1998, using natural gas HHV of 1,020 MMBtu/MMCF
4. Uncontrolled PTE determined from coal usage and sulfur content provided by the source and stoichiometry: (64 lb SO_2/lb mole) / (32 lb S/lb mole)

Methodology
Bottlenecked PTE (tons/yr) = Potential Sulfur Production (tons of sulfur/yr) x Emission Factor (lb/ton) / 2,000 (lb/ton) *SO_2*
Bottlenecked PTE (tons/yr) = Bottlenecked Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8,760 (hr/yr) / 2,000 (lb/ton) *all others*
Uncontrolled Bottlenecked PTE (tons/yr) = Potential Sulfur Production (tons of sulfur/yr) x 64 (lb SO_2/lb mole) / 32 (lb S/lb mole)

Appendix A: Emission Calculations
Tail Gas Treatment Units

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

2. Hazardous Air Pollutants

	Pollutant					
	Benzene	Formaldehyde	n-Hexane	Toluene	Nickel	Total HAPs
Emission Factor[1] (lb/MMBtu)	1.47E-06	5.25E-05	1.26E-03	2.38E-06	1.47E-06	-
Bottlenecked PTE (tons/yr)	4.86E-04	1.73E-02	0.42	7.86E-04	4.86E-04	0.43

Notes:
1. Emission factors from PTE calculations provided by the source.

	Pollutant			
	Sulfuric Acid Mist	H_2S	Total Reduced Sulfur	
Emission Factor (lb/MMBtu)	0.0244	-	0.0125	
BACT limit (ppmv)	-	10	-	
Bottlenecked PTE (tons/yr)	8.05	5.11	4.13	
Emission rate (lb/long ton S)	0.28	0.18	0.14	for comparison to RBLC entries

Methodology
Bottlenecked PTE (tons/yr) = Exhaust Molar Flow Rate (bottlenecked) (dry) (lb mole/min @ 0% O_2) x BACT Limit (ppmv) / 1,000,000 (ppmv/mole fraction) x 60 (min/hr) x 8,760 (hr/yr) / 2,000 (lb/ton) x 2 x 34 (lb H_2S/lb mole) *H_2S*
Bottlenecked PTE (tons/yr) = Bottlenecked Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8,760 (hr/yr) / 2,000 (lb/ton) *all others*
Total HAPs (tons/yr) = sum of named HAPs
Emission rate (lb/long ton S) = Bottlenecked PTE (tons/yr) x 2,000 (lb/ton) / [Bottlenecked Throughput (tons S/yr) / 1.1 (ton/long ton)]

3. Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO_2	CH_4	N_2O
Emission Factor in lb/MMBtu	123.2	0	2.16E-03
Potential Emission in tons/yr	40,660	0	0.71
Summed Potential Emissions in tons/yr	40,661		
CO2e Total in tons/yr	40,872		

Methodology
CO_2 emission factor provided by the source, includes CO_2 in the ARU acid gas stream
CH_4 emissions considered negligible because the SRU's are fueled with hydrogen sulfide
N_2O emission factor scaled from AP 42, Table 1.4-2 using natural gas HHV of 1,020 MMBtu/MMCF
Emission (tons/yr) = Throughput (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760 hr/yr x 1 ton/2,000 lb
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
CO_2e (tons/yr) = CO_2 Potential Emission ton/yr x CO_2 GWP (1) + CH_4 Potential Emission ton/yr x CH_4 GWP (25) + N_2O Potential Emission ton/yr x N_2O GWP (298).

Appendix A: Emission Calculations
Tail Gas Treatment Units

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

4. Potential to Emit After Issuance

	Pollutant									
	PM	PM_{10}	direct $PM_{2.5}$	SO_2	NOx	VOC	CO	H_2S	H_2SO_4 mist	CO_2e
Emission Limit[1] in lb/MMBtu	0.0019	0.0074	0.0074		0.10	0.0054	0.082		0.0244	
Emission Limit[1] (hourly) in ppmv (at 0% excess air)				167				10		
Emission Limit[1] (annual) in ppmv (at 0% excess air)				150						
Compliance determination coefficient (ton CO_2e/ton S)										0.641
Emissions Limitation, lb/hr (maximum, each SRU)	0.10	0.39	0.39	26.30	5.28	0.28	4.33	0.84	1.29	
Emissions Limitation, lb/hr (bottlenecked, combined)	0.14	0.56	0.56	36.70	7.54	0.41	6.18	1.17	1.84	
Potential to Emit After Issuance (tons/yr)	0.61	2.44	2.44	144.39	33.00	1.78	27.06	5.11	8.05	40,872

Notes:

1. BACT specifications

Methodology

SO_2, based on ideal gas behavior and stack discharge at 1 atmosphere

Emissions Limitation (maximum, each SRU) (lb/hr) = Exhaust Molar Flow Rate (maximum) (dry) (lb mole/min @ 0% O_2) x Emission Limit (hourly) (ppmv) / 1,000,000 (ppmv) x 64 (lb SO_2/lb mole) x 60 (min/hr) *SO_2*

Emissions Limitation (bottlenecked, combined) (lb/hr) = Exhaust Molar Flow Rate (bottlenecked) (dry) (lb mole/min @ 0% O_2) x Emission Limit (hourly) (ppmv) / 1,000,000 (ppmv) x 64 (lb SO_2/lb mole) x 60 (min/hr) x 2 *SO_2*

Emissions Limitation (maximum, each SRU) (lb/hr) = Exhaust Molar Flow Rate (maximum) (dry) (lb mole/min @ 0% O_2) x Emission Limit (ppmv) / 1,000,000 (ppmv) x 34 (lb H_2S/lb mole) x 60 (min/hr) *H_2S*

Emissions Limitation (bottlenecked, combined) (lb/hr) = Exhaust Molar Flow Rate (bottlenecked) (dry) (lb mole/min @ 0% O_2) x Emission Limit (ppmv) / 1,000,000 (ppmv) x 34 (lb H_2S/lb mole) x 60 (min/hr) x 2 *H_2S*

Emissions Limitation (maximum, each SRU) (lb/hr) = Maximum Heat Input Capacity (MMBtu/hr) x Emission Limit (lb/MMBtu) *all others*

Emissions Limitation (bottlenecked, combined) (lb/hr) = Bottlenecked Heat Input Capacity (MMBtu/hr) x Emission Limit (lb/MMBtu) *all others*

Potential to Emit After Issuance (tons/yr) = Exhaust Molar Flow Rate (bottlenecked) (dry) (lb mole/min @ 0% O_2) x Emission Limit (annual) (ppmv) / 1,000,000 (ppmv) x 64 (lb SO_2/lb mole) x 60 (min/hr) x 8,760 (hr/yr) / 2,000 (lb/ton) x 2 *SO_2*

Potential to Emit After Issuance (tons/yr) = Exhaust Molar Flow Rate (bottlenecked) (dry) (lb mole/min @ 0% O_2) x Emission Limit (ppmv) / 1,000,000 (ppmv) x 34 (lb H_2S/lb mole) x 60 (min/hr) x 8,760 (hr/yr) / 2,000 (lb/ton) x 2 *H_2S*

Potential to Emit After Issuance (tons/yr) = Bottlenecked Heat Input Capacity (MMBtu/hr) x Emission Limit (lb/MMBtu) x 8,760 (hr/yr) / 2,000 (lb/ton) *all others*

5. Preheat Potential to Emit

	Each	Combined	
A-602A and A-602B preheat/dryout heat input capacity:	40.00	80.00	MMBtu/hr
HHV:	1,009		MMBtu/MMCF
Potential Throughput:	347.27	694.55	MMCF/yr

	Pollutant						
	PM	PM_{10}	direct $PM_{2.5}$	SO_2	NOx	VOC	CO
Emission Factor (gr/scf)[1]	-	-	-	0.005	-	-	-
Emission Factor (lb/MMCF)[2]	1.9	7.6	7.6	-	100	5.50	84
Preheat PTE (lb/hr)	0.15	0.60	0.60	0.06	7.93	0.44	6.66

Notes:

1. BACT specification for refinery fuel gas combustion

2. Tables 1.4-1 and !.4-2, AP-42, 5th ed., July 1998

Methodology

Preheat PTE (lb/hr) = Emission Factor (gr/scf) x Combined Heat Input Capacity (MMBtu/hr) / HHV (MMBtu/MMCF) x 1,000,000 (scf/MMCF) / 7,000 (gr/lb) *SO_2*

Preheat PTE (lb/hr) = Emission Factor (lb/MMCF) x Combined Heat Input Capacity (MMBtu/hr) / HHV (MMBtu/MMCF) *all others*

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
HP, LP, and SB Flare Pilots

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. Flare Pilots

		Rating (MMBtu/hr) LHV (909 Btu/scf)	Rating (MMBtu/hr) HHV (1009 Btu/scf)	
SB Flare	EU-4002	0.77	0.85	Sulfur block flare includes continuous purge from sour water storage tanks.
LP Flare	EU-4003	6.50	7.22	LP flare includes continuous purge from Block 2000 slop tank.
HP Flare	EU-4004	6.50	7.22	Pilot operation considered representative of potential to emit.
Total			**15.28**	

		Heat Input Capacity (HHV) MMBtu/hr	HHV MMBtu / MMCF	Potential Throughput MMCF/yr
SB Flare	EU-4002	0.85	1009	7.42
LP Flare	EU-4003	7.22	1009	62.64
HP Flare	EU-4004	7.22	1009	62.64
			Total	**132.70**

	Pollutant						
	PM	PM$_{10}$	direct PM$_{2.5}$	SO$_2$	NOx	VOC	CO
Emission Limit[1] in gr S/scf	-	-	-	0.0064	-	-	-
Emission Factor (lb/MMBtu)[1]	0.0019	0.0074	0.0074	-	0.099	0.0054	0.083
SB Flare (lb/hr)	1.62E-03	6.32E-03	6.32E-03	1.55E-03	8.46E-02	4.62E-03	7.09E-02
LP Flare (lb/hr)	0.014	0.053	0.053	0.013	0.71	0.039	0.60
HP Flare (lb/hr)	0.014	0.053	0.053	0.013	0.71	0.039	0.60
Potential Emission in tons/yr	0.13	0.50	0.50	0.12	6.63	0.36	5.56

Notes:
1. PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
2. Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32
3. Worst-case factor provided by the source based on local natural gas composition and use of fractionator tower overhead in fuel gas supply, subject to testing.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Unit SO$_2$ PTE (lb/hr) = Emission Limit (gr/dscf) x Heat Input Capacity (HHV) (MMBtu/hr) / HHV (MMBtu/MMCF) x 1,000,000 (SCF/MMCF) / 7,000 (gr/lb) / 2,000 (lb/ton)
x 64 lb SO2/lb mole / 32 lb S/lb mole *SO$_2$*
Unit PTE (lb/hr) = Heat Input Capacity (HHV) (MMBtu/hr) x Emission Factor (lb/MMBtu) *all others*
PTE (tons/yr) = Potential Throughput (MMCF/yr) x Emission Limit (gr/scf) x1,000,000 (scf/MMCF) / 7,000 (gr/lb) / 2,000 lb/ton x 64 lb SO2/lb mole / 32 lb S/lb mole *SO$_2$*
PTE (tons/yr) = Total Heat Input Capacity (HHV) (MMBtu/hr) x Emission Limit (lb/MMBtu) x 8,760 (hr/yr) / 2,000 lb/ton *all others*

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	n-Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	7.79E-06	4.45E-06	2.78E-04	6.68E-03	1.26E-05	**6.98E-03**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	1.86E-06	4.08E-06	5.19E-06	1.41E-06	7.79E-06	**2.03E-05**
					Total HAPs	**7.00E-03**
					Worst HAP	**6.68E-03**

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

Greenhouse Gases (GHGs)

		Greenhouse Gas		
		CO2	CH4	N2O
Emission Factor in lb/MMcf		120,000	2.3	2.2
Potential Emission in tons/yr	SB Flare	445	0.01	0.01
	LP Flare	3,758	0.07	0.07
	HP Flare	3,758	0.07	0.07
Summed Potential Emissions in tons/yr		7,962		
CO2e Total in tons/yr	SB Flare	448		
	LP Flare	3,781		
	HP Flare	3,781		
	Total	8,009		

GHG compliance determination factor = 1079.36 (tons CO$_2$e/MMCF fuel gas)

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).
GHG compliance determination factor (tons CO$_2$e/MMCF fuel gas) = CO$_2$e Total (tons/yr) / Potential Throughput (MMCF/yr)

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
HP, LP, and SB Flare Pilots

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

2. Flare Operations[1]

			Flare Operating Conditions						
Plant Area	Source	Stream Type	Routed to	Events #/yr	Duration hr/event	Annual Period hr/yr	Flow Rate lb/hr	Stream Mol. Wt. lb/lbmol	Heating Value Btu/scf
Block 2000	VCC CCSU - 50 Bar Case Leak Test	N2	HP Flare EU-4004	2	2.5	5	98595	28.0	5
	VCC CCSU - 150 Bar Case Leak Test	N2 + H2	HP Flare EU-4004	2	7.5	15	45982	19.4	94
	VCC CCSU - 225 Bar Case Leak Test	N2 + H2	HP Flare EU-4004	2	11.25	22.5	21068	13.5	157
	VCC CCSU - 300 Bar Case Leak Test	N2 + H2	HP Flare EU-4004	2	15	30	12565	10.7	189
	VCC CCSU - Emergency Fast Depressure Test - 300 Bar	N2 + H2	HP Flare EU-4004	1	15	15	106231	4.3	368
	LPH CCSU - Purging	H2 + Light Hydrocarbons	LP EU-4003 HP EU-4004	2	168	336	4038	33.1	1706
	GPH CCSU - Catalyst Sulfiding	H2 + CH4 + H2S	LP EU-4003	2	48	96	530	9.2	539
	Product Stripper CCSU - Purging	Hydrocarbon	LP EU-4003 HP EU-4004	2	48	96	13601	38.9	1951
	LPH WSU - Purging	H2 + Hydrocarbon	LP EU-4003 HP EU-4004	6	8	48	4038	33.1	1706
	Product Stripper WSU - Purging	H2 + Hydrocarbon	LP EU-4003 HP EU-4004	6	8	48	13601	38.9	1951
Block 3000	Amine Regeneration Unit CCSU	Sour Acid Gas (H2S, CO2)	Sulfur Flare EU-4002	6	1	6	757	32.1	521
	Sour Water Stripping Unit - CCSU	NH3 + Sour Gas	Sulfur Flare EU-4002	6	1	6	2596	32.8	563
Block 7000	H2 Plant 1 CCSU - Desulfurizing Vent	Feed Nat Gas	LP Flare EU-4003	2	1	2	13340	16.5	880
	H2 Plant 1 CCSU - Reformer Vent	Reformed Gas	LP Flare EU-4003	2	12	24	41967	12.4	204
	H2 Plant 1 CCSU - Shift Converter Vent	Shifted Gas	LP Flare EU-4003	2	4	8	41967	12.4	200
	H2 Plant 1 CCSU - PSA Feed Vent	Dry Shifted Gas	LP Flare EU-4003	2	1	2	5718	12.5	282
	H2 Plant 1 CCSU - PSA Purge Vent	PSA Tail Gas	LP Flare EU-4003	2	1	2	35039	26.9	252
	H2 Plant 1 WSU - Reformer Vent	Reformed Gas	LP Flare EU-4003	1	8	8	41967	12.4	204
	H2 Plant 1 WSU - Shift Converter Vent	Shifted Gas	LP Flare EU-4003	1	1	1	41967	12.4	200
	H2 Plant 1 WSU - PSA Feed Vent	Dry Shifted Gas	LP Flare EU-4003	1	1	1	5718	12.5	282
	H2 Plant 1 WSU - PSA Purge Vent	PSA Tail Gas	LP Flare EU-4003	1	1	1	35039	26.9	252
	H2 Plant 2 CCSU - Desulfurizing Vent	Feed Nat Gas	LP Flare EU-4003	2	1	2	13340	16.5	880
	H2 Plant 2 CCSU - Reformer Vent	Reformed Gas	LP Flare EU-4003	2	12	24	41967	12.4	204
	H2 Plant 2 CCSU - Shift Converter Vent	Shifted Gas	LP Flare EU-4003	2	4	8	41967	12.4	200
	H2 Plant 2 CCSU - PSA Feed Vent	Dry Shifted Gas	LP Flare EU-4003	2	1	2	5718	12.5	282
	H2 Plant 2 CCSU - PSA Purge Vent	PSA Tail Gas	LP Flare EU-4003	2	1	2	35039	26.9	252
	H2 Plant 2 WSU - Reformer Vent	Reformed Gas	LP Flare EU-4003	1	8	8	41967	12.4	204
	H2 Plant 2 WSU - Shift Converter Vent	Shifted Gas	LP Flare EU-4003	1	1	1	41967	12.4	200
	H2 Plant 2 WSU - PSA Feed Vent	Dry Shifted Gas	LP Flare EU-4003	1	1	1	5718	12.5	282
	H2 Plant 2 WSU - PSA Purge Vent	PSA Tail Gas	LP Flare EU-4003	1	1	1	35039	26.9	252

Plant Area	Source	Hourly Emission Rates[2]					Annual Emission Rates[2]				
		NOx lb/hr	CO lb/hr	SO2 lb/hr	VOC lb/hr	CO2e lb/hr	NOx ton/yr	CO ton/yr	SO2 ton/yr	VOC ton/yr	CO2e ton/yr
Block 2000	VCC CCSU - 50 Bar Case Leak Test	0.44	2.40	0.01	0.04	886	0.001	0.006	0.000	0.000	2
	VCC CCSU - 150 Bar Case Leak Test	5.92	32.23	0.01	0.04	886	0.044	0.242	0.000	0.000	7
	VCC CCSU - 225 Bar Case Leak Test	6.55	35.63	0.01	0.04	886	0.074	0.401	0.000	0.000	10
	VCC CCSU - 300 Bar Case Leak Test	5.92	32.21	0.01	0.04	886	0.089	0.483	0.000	0.001	13
	VCC CCSU - Emergency Fast Depressure Test -	242.91	1321.71	4.95	338.89	178434	1.82	9.91	0.04	2.54	1338
	LPH CCSU - Purging	5.61	30.14	82.58	67.14	11558	0.94	5.06	13.87	11.28	1942
	GPH CCSU - Catalyst Sulfiding	0.82	4.48	119.73	0.04	1155	0.04	0.22	5.75	0.00	55
	Product Stripper CCSU - Purging	19.20	99.02	387.11	219.56	38803	0.92	4.75	18.58	10.54	1863
	LPH WSU - Purging	5.61	30.14	82.58	67.14	11558	0.13	0.72	1.98	1.61	277
	Product Stripper WSU - Purging	19.20	99.02	387.11	219.56	38803	0.46	2.38	9.29	5.27	931
Block 3000	Amine Regeneration Unit CCSU	0.33	1.78	1128.94	0.01	179	0.001	0.005	3.39	0.000	1
	Sour Water Stripping Unit - CCSU	1.90	6.47	4545.82	0.01	104	0.006	0.019	13.64	0.000	0
Block 7000	H2 Plant 1 CCSU - Desulfurizing Vent	19.00	103.36	0.54	1.52	37955	0.019	0.103	0.001	0.002	38
	H2 Plant 1 CCSU - Reformer Vent	18.44	300.79	0.01	0.04	30037	0.221	3.609	0.000	0.000	360
	H2 Plant 1 CCSU - Shift Converter Vent	18.04	113.42	0.01	0.04	30328	0.072	0.454	0.000	0.000	121
	H2 Plant 1 CCSU - PSA Feed Vent	3.44	25.20	0.01	0.04	6771	0.003	0.025	0.000	0.000	7
	H2 Plant 1 CCSU - PSA Purge Vent	8.74	93.56	0.01	0.04	42727	0.009	0.094	0.000	0.000	43
	H2 Plant 1 WSU - Reformer Vent	18.44	300.79	0.01	0.04	30037	0.074	1.203	0.000	0.000	120
	H2 Plant 1 WSU - Shift Converter Vent	18.04	113.42	0.01	0.04	30328	0.009	0.057	0.000	0.000	15
	H2 Plant 1 WSU - PSA Feed Vent	3.44	25.20	0.01	0.04	6771	0.002	0.013	0.000	0.000	3
	H2 Plant 1 WSU - PSA Purge Vent	8.74	93.56	0.01	0.04	42727	0.004	0.047	0.000	0.000	21
	H2 Plant 2 CCSU - Desulfurizing Vent	19.00	103.36	0.54	1.52	37955	0.019	0.103	0.001	0.002	38
	H2 Plant 2 CCSU - Reformer Vent	18.44	300.79	0.01	0.04	30037	0.221	3.609	0.000	0.000	360
	H2 Plant 2 CCSU - Shift Converter Vent	18.04	113.42	0.01	0.04	30328	0.072	0.454	0.000	0.000	121
	H2 Plant 2 CCSU - PSA Feed Vent	3.44	25.20	0.01	0.04	6771	0.003	0.025	0.000	0.000	7
	H2 Plant 2 CCSU - PSA Purge Vent	8.74	93.56	0.01	0.04	42727	0.009	0.094	0.000	0.000	43
	H2 Plant 2 WSU - Reformer Vent	18.44	300.79	0.01	0.04	30037	0.074	1.203	0.000	0.000	120
	H2 Plant 2 WSU - Shift Converter Vent	18.04	113.42	0.01	0.04	30328	0.009	0.057	0.000	0.000	15
	H2 Plant 2 WSU - PSA Feed Vent	3.44	25.20	0.01	0.04	6771	0.002	0.013	0.000	0.000	3
	H2 Plant 2 WSU - PSA Purge Vent	8.74	93.56	0.01	0.04	42727	0.004	0.047	0.000	0.000	21
Total							**5.36**	**35.41**	**66.54**	**31.25**	**7,898**

Notes:

1. Information provided by the source based on expected operating conditions.

2. Pilots & purge gas contributions included in emissions

CCSU = Commissioning/Cold Start-up, WSU = Warm Start-up

MMBH-L = MMBtu/hr (LHV)

Reformed Gas = Hydrogen Plants' Reformer and downstream mixes derived from Natural Gas and LPG feedstock

3. Potential to Emit After Issuance

	Pollutant (tons/yr)							
	PM	PM_{10}	direct $PM_{2.5}$	SO_2	NOx	VOC	CO	CO_2e
Potential to Emit After Issuance	0.13	0.50	0.50	66.66	11.99	31.61	40.97	15,908

Methodology

PTE after Issuance (tons/yr) = sum of totals from sections 1 and 2

Appendix A: Emissions Calculations
Loading Rack Flare (EU-4001)

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. Flare Stream Emissions

	Molecular Weight[1], M (lb/lb mole)	Loading Loss[2], L_L (lb/kgal)	Annual Throughput[1] (kgal/yr)	VOC Input (lb/yr)	Heat	
					Content[3] (MMBtu/lb)	Input (MMBtu/yr)
Naphtha	90.55	2.45	112,721	276,406	0.0202	5573.18
Distillate	192.39	0.05	220,277	11,230	0.0196	219.93
Total			332,998	287,636		**5793.11**

Notes:
1. Vapor molecular weights calculated in "Product Vapor HAP" tab.
2. Loading loss calculated in "Block 4000 Racks" tab.
3. Product heat content provided by the source, 7/26/2018.

Methodology
VOC Input (lb/yr) = Loading Loss (lb/kgal) x Annual Throughput (kgal/yr)
Heat Input (MMBtu/yr) = VOC Input (lb/yr) x Heat Content (MMBtu/lb)

A. Criteria Pollutants

	Pollutant						
	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO
Emission Factor[1] (lb/MMBtu)	-[2]	-[2]	-[2]	-[3]	0.068	-[4]	0.31
Potential to Emit (tons/yr)					0.20		0.90

Notes:
1. Emission factor source, Tables 13.5-1 and 13.5-2, AP-42 (2/18) except as noted.
2. Particulate matter (soot) emissions negligible for nonsmoking flare, ref. note d, AP-42 Table 13.5-1 (2/18).
3. Sulfur content of hydrotreated products considered negligible.
4. VOC emissions are accounted for in the loading rack PTE.

Methodology
Potential to Emit (tons/yr) = Emission Factor (lb/MMBtu) x Total Heat Input (MMBtu/yr) / 2,000 (lb/ton)

B. Hazardous Air Pollutants

HAP Emissions are accounted for in the loading rack PTE.

C. Greenhouse Gases (GHGs)

Given that alkanes have the nominal formula C_nH_{2n+2}
and the atomic weights of C = 12 and H = 1, then the molecular weight is M = 12n + 2n + 2, and n = (M-2)/14

	VOC Input[1] (lb/yr)	Molecular Weight[1], M (lb/lb mole)	VOC Input (lb mole/yr)	n (lb mole CO_2 /lb mole VOC)	Molar CO_2 Emissions (lb mole/yr)	Molar CO Emissions (lb mole/yr)	CO_2 Emissions (tons/yr)
Naphtha	276,406	90.55	3052.40	6.33	19307	62	423
Distillate	11,230	192.39	58.37	13.60	794	2	17

Notes:
1. Section 1

Methodology
VOC Input (lb mole/yr) = VOC Input (lb/yr) / Molecular Weight (lb/lb mole)
n (lb mole CO_2/lb mole VOC)= (M-2)/14
CO_2 Emissions (lb mole/yr) = VOC Input (lb mole/yr) x n (lb mole CO_2/lb mole VOC)
Molar CO Emissions (lb mole/yr) = Product Heat Input (MMBtu/yr) x CO Emission Factor (lb/MMBtu) / 28 (lb/lb mole)

Potential to Emit

		Greenhouse Gas		
		CO_2	CH_4	N_2O
Emission Factor in lb/kgal		-	0.216	0.26
Emission Factor in lb/lb VOC		-	3.04E-05	3.66E-05
Potential Emission in tons/yr	Naphtha	423	4.20E-03	5.06E-03
	Diesel	17	1.71E-04	2.06E-04
Summed Potential Emissions in tons/yr	Naphtha	423		
	Diesel	17		
CO_2e Total in tons/yr	Naphtha	425		
	Diesel	17		
CO_2e compliance determination factor (tons CO_2e/kgal)	Naphtha	3.77E-03		
	Diesel	7.93E-05		

Methodology
CO_2 Potential Emission (tons/yr) = Molar CO_2 Emissions (lb mole/yr) x 44 (lb/lb mole) / 2,000 (lb/ton)
CH_4 and N_2O Emission Factors are from AP 42, Tables 1.3-3 and 1.3-8, (SCC 1-03-005-01/02/03) Supplement E 9/99 (see errata file)
Emission factors for distillate oil combustion taken as representative.
Emission Factor (lb/lb VOC) = Emission Factor (lb/kgal) / 1,000 (gal/kgal) / 7.1 (lb/gal, *density of distillate oil*)
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = VOC Input (lb/yr) x Emission Factor (lb/lb VOC) / 2,000 lb/ton *CH_4 and N_2O*
CO_2e (tons/yr) = CO_2 Potential Emission ton/yr x CO_2 GWP (1) + CH_4 Potential Emission ton/yr x CH_4 GWP (25) + N_2O Potential Emission ton/yr x N_2O GWP (298).
CO_2e Compliance Determination Factor (tons CO_2e/kgal) = CO_2e Total (tons/yr) / Annual Throughput (kgal/yr)

Appendix A: Emissions Calculations
Loading Rack Flare (EU-4001)

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

2. Pilot Operation

		Rating (MMBtu/hr) LHV (909 Btu/scf)	 HHV (1009 Btu/scf)
Loading Rack Flare	EU-4001	0.20	0.22
Total			**0.22**

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
0.22	1009	1.9

	Pollutant						
	PM	PM_{10}	direct $PM_{2.5}$	SO_2	NOx	VOC	CO
Emission Factor (ppmv H_2S)[1]	-	-	-	162	-	-	-
Emission Factor (lb/MMBtu)[1]	0.0019	0.0074	0.0074	0.0008	0.099	0.0054	0.083
Potential Emission (lb/hr)	4.22E-04	1.64E-03	1.64E-03	1.87E-04	2.20E-02	1.20E-03	1.84E-02
Potential Emission (tons/yr)	1.85E-03	7.20E-03	7.20E-03	8.19E-04	0.10	5.25E-03	8.07E-02

Notes:
1. BACT specifications
PM2.5 emission factor is filterable and condensable PM2.5 combined.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
SO_2 Emission Limit (lb/MMBtu) = Emission Limit (ppmv) / 1,000,000 / 359 (lb mole/ft^3) x 1,000,000 (scf/MMCF) / HHV (MMBtu/MMCF) x 64 lb SO_2/lb mole / 34 lb H_2S/lb mole
note: Volume fractions equal mole fraction, so ppmv/1,000,000=mole fraction, molar volume standard conditions (1 atm, 273.15 K), molar volume V' = RT/P = 359 ft^3/lb-mole from the ideal gas law
PTE (tons/yr) = Potential Throughput (MMCF/yr) x HHV (MMBtu/MMCF) x Emission Limit (lb/MMBtu) x 8,760 (hr/yr) / 2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	n-Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	2.02E-06	1.16E-06	7.23E-05	1.73E-03	3.28E-06	**1.81E-03**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	4.82E-07	1.06E-06	1.35E-06	3.66E-07	2.02E-06	**5.28E-06**

Total HAPs	**1.82E-03**
Worst HAP	**1.73E-03**

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

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	116	2.22E-03	2.12E-03
Summed Potential Emissions in tons/yr	116		
CO2e Total in tons/yr	116		

GHG compliance determination factor = 60.36

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).
GHG Compliance Determination Factor (tons CO_2e/MMCF fuel gas) = CO_2e Total (tons/yr) / Potential Throughput (MMCF/yr)

3. Potential to Emit After Issuance

	Pollutant							
	PM	PM_{10}	direct $PM_{2.5}$	SO_2	NOx	VOC	CO	CO_2e
Flare Steam (tons/yr)	-	-	-	-	0.20	-	0.90	442
Pilot Operations (tons/yr)	1.85E-03	7.20E-03	7.20E-03	8.19E-04	9.63E-02	5.25E-03	8.07E-02	116
Total	1.85E-03	7.20E-03	7.20E-03	8.19E-04	0.29	5.25E-03	0.98	559
Modeled emission rates (lb/hr)	4.22E-04	1.64E-03	1.64E-03	1.87E-04	6.69E-02	1.20E-03	2.23E-01	

Methodology
Modeled emission rates (lb/hr) = Total (tons/yr) / 8,760 (hr/yr) x 2,000 (lb/ton)

Appendix A: Emissions Calculations
Product Loading Rack

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. VOC

Uncontrolled loading loss from AP-42 Chapter 5.2, Eqn. 1.

L_L = 12.46 (SPM / T)

Where L_L = Loading Loss (lb/kgal)
S = a saturation factor, AP-42 Table 5.2-1 (dimensionless)
P = true vapor pressure of liquid loaded, (psia) (AP-42 Table 7.1-2 or other standard engineering sources)
M = vapor molecular weight (lb/lb mole) (AP-42 Table 7.1-2 or other standard engineering sources)
T = temperature of bulk liquid loaded, (°R)

Fuel Type[1]	Saturation Factor[2]	True Vapor Pressure[3] (psia)	Molecular Weight[4] (lb/lb-mole)	Temperature[5] (°R)	L_L Loading Loss (lb/kgal)	Annual Throughput[6] (kgal/yr)	Uncontrolled VOC PTE (ton/yr)	Emission Control Efficiency (%)	Controlled VOC Emissions (ton/yr)	Emissions Limit (lb/kgal)
Naphtha loading	1.0	1.17	90.55	537.97	2.45	112,721	138.20	98%	2.76	0.049
Distillate loading	1.0	1.14E-02	192.39	537.97	0.051	220,277	5.61	98%	0.11	1.02E-03
Total							**143.8**		**2.88**	

Notes:
1. *The source has stated there are no emissions from sulfur loading or ammonia loading.*
2. *Vapor balance service, submerged loading*
3. *Vapor pressure determined using August Equation (Eqn 1-24, AP-42 Chapter 7) with coefficients for naphtha and diesel from "Product Vapor HAP" tab.*
4. *Vapor molecular weights calculated in "Product Vapor HAP" tab.*
5. *Temperature is maximum monthly average temperature from meteorological data in TANKS 4.0.9d for Evansville, Indiana*
6. *Annual product throughput from "Block 4000 Tanks" tab.*

Methodology
1 kgal = 1,000 gal
Vapor recovery collection efficiency is from AP-42 Chapter 5.2.
Uncontrolled VOC PTE (ton/yr) = Annual throughput (kgal/yr) x loading loss (lb/kgal) x 1 ton / 2000 lb
Controlled VOC PTE (ton/yr) = Uncontrolled VOC PTE (ton/yr) x [1 - (Control Eff x Collection Eff.)]
Emissions Limit (lb/kgal) = L_L (lb/kgal) x (1-Control Efficiency (%)/100)

2. Hazardous Air Pollutants

	HAP as Weight Fraction of VOC[1]						
HAP	Benzene	o-Cresol	m- & p-Cresol	n-Hexane	Phenol	Toluene	Xylenes
CASRN	71-43-2	95-48-7	-	110-54-3	108-95-2	108-88-3	1330-20-7
Naphtha[3]	2.21E-02	9.28E-06	1.60E-06	1.03E-01	3.70E-06	1.89E-02	6.86E-03
Diesel[4]	1.54E-02	1.61E-05	6.67E-06	0	1.54536E-05	4.94E-03	4.30E-03

Notes:
1. *Vapor HAP fractions calculated in "Product Vapor HAP" tab.*

	Uncontrolled Potential to Emit (tons/yr)							
	Benzene	o-Cresol	m- & p-Cresol	n-Hexane	Phenol	Toluene	Xylenes	Total
Naphtha	3.06	1.28E-03	2.21E-04	14.22	5.12E-04	2.62	0.95	20.85
Diesel	8.65E-02	9.06E-05	3.75E-05	0	8.68E-05	2.77E-02	2.41E-02	1.39E-01
Total	**3.15**	**1.37E-03**	**2.58E-04**	**14.22**	**5.99E-04**	**2.64**	**0.97**	**20.99**

	Potential to Emit After Issuance (tons/yr)							
	Benzene	o-Cresol	m- & p-Cresol	n-Hexane	Phenol	Toluene	Xylenes	Total
Naphtha	6.12E-02	2.57E-05	4.42E-06	0.28	1.02E-05	5.23E-02	1.90E-02	0.42
Diesel	1.73E-03	1.81E-06	7.49E-07	0	1.74E-06	5.55E-04	4.82E-04	2.77E-03
Total	**6.29E-02**	**2.75E-05**	**5.17E-06**	**0.28**	**1.20E-05**	**5.29E-02**	**1.95E-02**	**0.42**

Appendix A: Emissions Calculations
Tanks VOC

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. VOC

					Calculated Losses (lb/yr)							
Tank ID	Tank Type:	Materials Stored	Capacity (gal)	Annual Throughput (gal/yr)	Rim Seal Loss	Withdrawal Loss	Deck Fitting Loss	Deck Seam Loss	Working Loss	Breathing Loss	Total PTE (tons/yr)	Total PTE (lb/hr)
T1	DIFR	Naphtha Product Tank 1	4,629,879	112,721,490	1,886.82	151.76	256.65	0	-	-	1.15	0.26
T2	DIFR	Naphtha Product Tank 2	4,629,879	112,721,490	1,886.82	151.76	256.65	0	-	-	1.15	0.26
T3	Fixed Roof	Diesel Product Tank 1	4,525,796	220,276,770	-	-	-	-	3262.19	1316.87	2.29	0.52
T4	Fixed Roof	Diesel Product Tank 2	4,525,796	220,276,770	-	-	-	-	3262.19	1316.87	2.29	0.52
T5	Fixed Roof	Diesel Product Tank 3	4,525,796	220,276,770	-	-	-	-	3262.19	1316.87	2.29	0.52
T6	DIFR	Product Swing Tank (naphtha)	4,629,879	112,721,490	1,886.82	151.76	256.65	0	-	-	1.15	0.26
		Product Swing Tank (diesel)		220,276,770	14.38	329	1.96	0	-	-	0.17	0.04
T7	Fixed Roof	Molten Sulfur Tank 1	342,367	8,554,779	-	-	-	-	-	-	-	-
T8	Fixed Roof	Molten Sulfur Tank 2	342,367	8,554,779	-	-	-	-	-	-	-	-
T9		Ammonia Product Storage Bullets	36,720	15,024,167	-	-	-	-	-	-	-	-
		Intermediate Storage										
T10	Fixed Roof	Residue Surge Tank (VR LPH) 1	926,980	72,299,756	-	-	-	-	0.00	0.00	0.00	0.00
T11	Fixed Roof	Residue Surge Tank (VR LPH) 2	926,980	72,299,756	-	-	-	-	0.00	0.00	0.00	0.00
T12	Fixed Roof	Residue Feed Tank	926,980	72,299,756	-	-	-	-	0.00	0.00	0.00	0.00
T13	Fixed Roof	VGO Tank 1	926,980	154,497	-	-	-	-	0.00	0.00	0.00	0.00
T14	Fixed Roof	VGO Tank 2	926,980	154,497	-	-	-	-	0.00	0.00	0.00	0.00
T15		LPG Storage Bullets	48,872	1,793,464	-	-	-	-	0	0	0	0
		Auxiliaries Storage										
T16	Fixed Roof	Slop Tank	4,195,581	305,467,367	-	-	-	-	3286.21	1069.98	2.18	0.50
T17	Fixed Roof	Diesel fuel storage tank	23,775	300,000	-	-	-	-	5.58	8.14	6.86E-03	1.57E-03
T18	Fixed Roof	Non-Phenolic Sour Water Storage Tank 1	1,268,026	462,829,344	-	-	-	-	0	0	0	0
T19	Fixed Roof	Non-Phenolic Sour Water Storage Tank 2	1,268,026	462,829,344	-	-	-	-	0	0	0	0
T20	Fixed Roof	Non-Phenolic Sour Water Storage Tank 3	1,268,026	462,829,344	-	-	-	-	0	0	0	
T21	Fixed Roof	Phenolic Sour Water Storage Tank	40,947	4,628,293	-	-	-	-	0	0	0	0
T22	Fixed Roof	Stripped Non-Phenolic Sour Water Surge Tank	1,268,026	462,829,344	-	-	-	-	0	0	0	0
T23	Fixed Roof	Stripped Phenolic Sour Water Surge Tank	13,737	4,628,293	-	-	-	-	0	0	0	0
T24	Fixed Roof	Amine Surge/Deinventory Tank	63,943	63,943	-	-	-	-	0.01	0	5.00E-06	1.14E-06
T25	Fixed Roof	Fresh Amine Tank	63,943	63,943	-	-	-	-	0.01	0	5.00E-06	1.14E-06
T26	Fixed Roof	Amine Containment Tank	793	not specified	-	-	-	-	0	0	0	0
Total											**12.67**	

Note: Emissions from EPA TANKS 4.0.9d

Swing tank compliance determination factors (lb/day):	naphtha	6.29
(sum of calculated losses (lb/yr) / 365)	diesel	0.95

2. Hazardous Air Pollutants

	HAP as Weight Fraction of VOC[1]						
HAP	Benzene	o-Cresol	m- & p-Cresol	n-Hexane	Phenol	Toluene	Xylenes
CASRN	71-43-2	95-48-7	-	110-54-3	108-95-2	108-88-3	1330-20-7
Naphtha	2.21E-02	9.28E-06	1.60E-06	1.03E-01	3.70E-06	1.89E-02	6.86E-03
Diesel	1.54E-02	1.61E-05	6.67E-06	0.00E+00	1.55E-05	4.94E-03	4.30E-03

Notes:

1. See Product Vapor HAP tab for derivation of emission factors

				Potential to Emit (tons/yr)							
Tank ID	Tank Type:	Materials Stored	VOC PTE (tons/yr)	Benzene	o-Cresol	m- & p-Cresol	n-Hexane	Phenol	Toluene	Xylenes	Total
T1	DIFR	Naphtha Product Tank 1	1.15	2.54E-02	1.07E-05	1.83E-06	1.18E-01	4.25E-06	2.17E-02	7.88E-03	0.17
T2	DIFR	Naphtha Product Tank 2	1.15	2.54E-02	1.07E-05	1.83E-06	1.18E-01	4.25E-06	2.17E-02	7.88E-03	0.17
T3	Fixed Roof	Diesel Product Tank 1	2.29	3.53E-02	3.69E-05	1.53E-05	0	3.54E-05	1.13E-02	9.84E-03	5.65E-02
T4	Fixed Roof	Diesel Product Tank 2	2.29	3.53E-02	3.69E-05	1.53E-05	0	3.54E-05	1.13E-02	9.84E-03	5.65E-02
T5	Fixed Roof	Diesel Product Tank 3	2.29	3.53E-02	3.69E-05	1.53E-05	0	3.54E-05	1.13E-02	9.84E-03	5.65E-02
T6	DIFR	Diesel Product Swing Tank	1.15	2.54E-02	1.07E-05	1.83E-06	1.18E-01	4.25E-06	2.17E-02	7.88E-03	0.17
T16	Fixed Roof	Slop Tank	2.18	3.35E-02	3.52E-05	1.45E-05	0	3.37E-05	1.08E-02	9.36E-03	5.37E-02
T17	Fixed Roof	Diesel fuel storage tank	6.86E-03	1.06E-04	1.11E-07	4.58E-08	0	1.06E-07	3.39E-05	2.95E-05	1.69E-04
Total				**0.22**	**1.78E-04**	**6.59E-05**	**0.35**	**1.53E-04**	**1.10E-01**	**0.68**	**1.36**

Appendix A: Emission Calculations
Residue Solidification Units

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. Unrestricted Potential to Emit[1]

A. Pastillators

Unit	ID	Stack ID	Solidification Rate	VOC Emission Factor[2]	Potential to Emit VOC	
			ton/hr	lb/ton	lb/hr	ton/yr
Residue Solidification Unit	EU-5001a-d	S-5001	17.16	8.15E-02	1.40	6.12
Residue Solidification Unit	EU-5002a-d	S-5002	17.16	8.15E-02	1.40	6.12
Residue Solidification Unit	EU-5003a-d	S-5003	17.16	8.15E-02	1.40	6.12
Residue Solidification Unit	EU-5004a-d	S-5004	17.16	8.15E-02	1.40	6.12
Total					**5.59**	**24.50**

Notes:
1. Each unit has the capacity to process 1/3 of the total hourly residue production, 51.49 tons.
2. Emission factor derived by the source from mass transfer model.

Methodology
VOC Emission factor provided by source.
VOC PTE (ton/yr) = Solidification Rate (ton/hr) x VOC Emission Factor (lb/ton) x 8760 hr/yr x 1 ton / 2000 lb
VCC residue is the bottoms product of VCC Vacuum Distillation Tower where vacuum gas oil (VGO) is extracted for recycle. This residue is solidified (into pastilles) and cooled along a conveyor.

B. Pastille handling

	Number of Transfers	Throughput per transfer	Emission Factor (lb/ton)			Uncontrolled PTE (lb/hr)			Uncontrolled PTE (tons/yr)		
		(tons/hr)	PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$
Pastille line discharge to transfer conveyor[1] (EU-5001a-d, EU-5002a-d, EU-5003a-d, EU-5004a-d)	16	4.29	0.0030	0.0011	0.0011	0.21	0.08	0.08	0.90	0.33	0.33
transfer conveyor discharge to loading conveyor[1] (Block 1 & 2 transfer conveyor, Block 3 & 4 transfer conveyor)	2	34.33	0.0030	0.0011	0.0011	0.21	0.08	0.08	0.90	0.33	0.33
loading conveyor discharge to packaging or storage silo, silo transfer to loading hopper[1,3] (EU-5005, EU-5006, EU-5007, EU-5008, EU-5009, EU-5010, EU-5011)	-	51.49	0.0030	0.0011	0.0011	0.15	0.06	0.06	0.68	0.25	0.25
hopper discharge to transport[4]	-	-	-	-	-	-	-	-	-	-	-
Total									**2.48**	**0.91**	**0.91**

Notes:
1. Emission factor: conveyor transfer point, uncontrolled (SCC 3-05-020-06), Table 11.19.2-2, AP-42, 5th ed., August 2004
2. Residue cooling forms a glassy coat on material with some characteristics of bitumen.
3. Loading conveyor discharges to only one point at a time (EU-5009, EU-5010, or EU-5011). Transfer to loading hoppers EU-5005 and EU-5006 controlled by baghouse EU-5010
Transfer to loading hoppers EU-5007 and EU-5008 controlled by baghouse EU-5011.
4. Based on the bituminous (i.e., tarry) characteristics of the residue, IDEM considers that the emissions from loadout operations will be negligible. Use
of control devices for silos and hoppers is considered mainly to retain the material in the vessel rather than as an emission control.

Methodology
Uncontrolled PTE (lb/hr) = Number of transfers x Throughput per transfer (tons/hr) x Emission Factor (lb/ton)
PTE (tons/yr) = PTE (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

2. Bottlenecked Potential to Emit[1]

A. Pastillators

Unit	Solidification Rate	VOC Emission Factor	Potential to Emit VOC
	tons/yr	lb/ton	ton/yr
Block 5000	451,052	8.15E-02	18.37
Total			**18.37**

Notes:
1. Solidification process is bottlenecked by the amount of residue generated by the Block 2000 process, emission factor from section 1

B. Pastille handling

	Annual Throughput	Emission Factor (lb/ton)			Bottlenecked PTE (tons/yr) (Uncontrolled)		
	(tons/yr)	PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$
Pastille line discharge to transfer conveyor[1] (EU-5001a-d, EU-5002a-d, EU-5003a-d, EU-5004a-d)	451,052	0.0030	0.0011	0.0011	0.68	0.25	0.25
transfer conveyor discharge to loading conveyor[1] (Block 1 & 2 transfer conveyor, Block 3 & 4 transfer conveyor)	451,052	0.0030	0.0011	0.0011	0.68	0.25	0.25
loading conveyor discharge to packaging or storage silo, silo transfer to loading hopper[1,3] (EU-5005, EU-5006, EU-5007, EU-5008, EU-5009, EU-5010, EU-5011)	451,052	0.0030	0.0011	0.0011	0.68	0.25	0.25
hopper discharge to transport[4]	451,052	-	-	-	-	-	-
Total					**2.03**	**0.74**	**0.74**

Notes:
1. Emission factor: conveyor transfer point, uncontrolled (SCC 3-05-020-06), Table 11.19.2-2, AP-42, 5th ed., August 2004
2. Residue cooling forms a glassy coat on material with some characteristics of bitumen.
3. Loading conveyor discharges to only one point at a time (EU-5009, EU-5010, or EU-5011). Transfer to loading hoppers EU-5005 and EU-5006 controlled by baghouse EU-5010
Transfer to loading hoppers EU-5007 and EU-5008 controlled by baghouse EU-5011.
4. Based on the bituminous (i.e., tarry) characteristics of the residue, IDEM considers that the emissions from loadout operations will be negligible. Use
of control devices for silos and hoppers is considered mainly to retain the material in the vessel rather than as an emission control.

Methodology
Bottlenecked PTE = Annual Throughput (tons/yr) x Emission Factor (lb/ton) / 2,000 (lb/ton)

3. Potential to Emit After Issuance

A. Conveying processes	Unit	Air Flow Rate	Pollutant		
		(dscfm)	PM	PM_{10}	direct $PM_{2.5}$
Emissions Limitation[1] (gr/dscf)	EU-5009	49	0.002	0.002	0.002
Potential to Emit After Issuance (lb/hr)			0.001	0.001	0.001
Potential to Emit After Issuance (tons/yr)			3.68E-03	3.68E-03	3.68E-03
Emissions Limitation[1] (gr/dscf)	EU-5010	161	0.002	0.002	0.002
Potential to Emit After Issuance (lb/hr)			0.003	0.003	0.003
Potential to Emit After Issuance (tons/yr)			1.21E-02	1.21E-02	1.21E-02
Emissions Limitation[1] (gr/dscf)	EU-5011	161	0.002	0.002	0.002
Potential to Emit After Issuance (lb/hr)			0.003	0.003	0.003
Potential to Emit After Issuance (tons/yr)			1.21E-02	1.21E-02	1.21E-02
Total			**0.03**	**0.03**	**0.03**

Notes:
1. BACT specifications

Methodology
PTE After Issuance (lb/hr) = Air Flow Rate (dscfm) x Emissions Limitation (gr/dscf) x 60 (min/hr) / 7,000 (gr/lb)
PTE After Issuance (tons/yr) = PTE After Issuance (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
Boiler EU-6000

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
68.5	1009	594.7

1. Uncontrolled Potential to Emit

	Pollutant						
	PM[1]	PM_{10}[1]	direct $PM_{2.5}$[1]	SO_2	NOx	VOC	CO
Emission Factor in lb/MMCF (AP-42)	1.9	7.6	7.6	-	-	5.5	-
Emission Factor in lb/MMCF[2]	-	-	-	1.797	-	-	-
Emission Factor in lb/MMBtu[3]	-	-	-	-	0.04	-	0.036
Potential Emission in tons/yr	0.56	2.26	2.26	0.53	12.00	1.64	10.80

Notes:
1. PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
2. Worst-case factor provided by the source based on local natural gas composition and use of fractionator tower overhead in fuel gas supply, subject to testing.
3. Emission factors provided by the burner manufacturer, subject to testing.

Methodology
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission (tons/yr) = Throughput (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760 hr/yr x 1 ton/2,000 lb

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	n-Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	6.24E-04	3.57E-04	2.23E-02	0.54	1.01E-03	**0.56**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	1.49E-04	3.27E-04	4.16E-04	1.13E-04	6.24E-04	**1.63E-03**

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

Total HAPs	**0.56**
Worst HAP	**0.54**

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	0.64
Potential Emission in tons/yr	35,682	0.68	0.19
Summed Potential Emissions in tons/yr	35,683		
CO2e Total in tons/yr	35,756		

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

2. Potential to Emit After Issuance

	Pollutant							
	PM	PM_{10}	direct $PM_{2.5}$	SO_2	NOx	VOC	CO	CO_2e
Emission Limit[1] in lb/MMBtu	0.0019	0.0075	0.0075	-	0.030	0.0054	0.0365	-
Maximum Emission Limit[2] in gr S/scf	-	-	-	0.0062	-	-	-	-
Annual Emission Limit[3] in gr S/scf	-	-	-	0.005	-	-	-	-
Compliance determination coefficient (ton CO2e/MMCF)								60.12
Potential to Emit After Issuance in lb/hr	0.13	0.51	0.51	0.12	2.06	0.37	2.50	-
Potential to Emit After Issuance in tons/yr	0.57	2.25	2.25	0.42	9.00	1.62	10.95	35,756

Notes:
1. BACT specifications
2. Maximum
3. Twelve (12) month average

Methodology
Compliance determination coefficient (ton CO2e/MMCF) = CO_2e Total (tons/yr) / Potential Throughput (MMCF/yr)
PTE After Issuance (lb/hr) = Heat Input Capacity (MMBtu/hr) / HHV (MMBtu/MMCF) x 1,000,000 (SCF/MMCF) x Maximum Emission Limit (gr/scf) / 7,000 (gr/lb) x 64 (lb SO_2/lb-mole) / 32 (lb S/lb-mole) *SO_2*
PTE After Issuance (lb/hr) = Emission Limit (lb/MMBtu) x Heat Input Capacity (MMBtu/hr) *all others*
PTE After Issuance (tons/yr) = Heat Input Capacity (MMBtu/hr) / HHV (MMBtu/MMCF) x 1,000,000 (SCF/MMCF) x Annual Emission Limit (gr/scf) / 7,000 (gr/lb) x 64 (lb SO_2/lb-mole) / 32 (lb S/lb-mole)
x 8,760 (hr/yr) / 2,000 (lb/ton) *SO_2*
PTE After Issuance (tons/yr) = PTE After Issuance (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton) *all others*

Appendix A: Emission Calculations
Mechanical Draft Cooling Tower
EU-6001, EU-6002, EU-6003

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. Particulate

Circulating water flow rate (W_c)	32,000 gal/min	total of three cells, provided by the source
Drift loss	0.0005%	provided by the source

Blowdown/drift TDS	2395 mg/l	provided by the source

Unit ID	Total Liquid Drift (lb/10^3 gal)	Cell Flow Rate (gal/min)	Potential to Emit					
			PM		PM_{10}		$PM_{2.5}$	
			(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
EU-6001	4.17E-02	10,667	0.06	0.28	0.04	0.16	1.34E-04	5.85E-04
EU-6002		10,667	0.06	0.28	0.04	0.16	1.34E-04	5.85E-04
EU-6003		10,667	0.06	0.28	0.04	0.16	1.34E-04	5.85E-04
Total			**0.19**	**0.84**	**0.11**	**0.48**	**4.01E-04**	**1.75E-03**

Methodology

Methodology ref: par. 2, page 13.4-3, AP-42 (1/95)

Total Liquid Drift (lb/10^3 gal) = Drift loss (%) / 100 x 8.34 (lb/gal) x 1,000 (gal/10^3 gal)

PM PTE (lb/hr) = Total Liquid Drift (lb/10^3 gal) x Cell Flow Rate (gal/min) / 1,000 (gal/10^3 gal) x 60 (min/hr) x Blowdown/drift TDS (mg/l) / 1,000,000 (mg/l / weight fraction)

PM_{10}/$PM_{2.5}$ PTE (lb/hr) = PM PTE (lb/hr) x EPRI % Mass Smaller *(from interpolation table below)* / 100

PTE (tons/yr) = PTE (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

Particle Size Distribution

Cooling Tower Particle Size Distribution						
EPRI Droplet Diameter (μm)	Droplet Volume (μm^3)	Droplet Mass (μg)	Particle Mass (solids) (μg)	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm)	EPRI % Mass Smaller
20	4189	4.19E-03	1.00E-05	4.56	2.06	0.20
				Interpolation --->	**2.50**	**0.21**
30	14137	1.41E-02	3.39E-05	15.39	3.09	0.23
90	381704	3.82E-01	9.14E-04	415.54	9.26	49.81
				Interpolation --->	**10.00**	**57.27**
110	696910	6.97E-01	1.67E-03	758.68	11.32	70.51

Particle Size Distribution based on approach presented in: *Calculating Realistic PM10 Emissions from Cooling Towers* Joel Reisman and Gordon Frisbie, Environmental Progress (Vol 21, No 2), July 2002

2. VOC

Unit ID	Cell Flow Rate (gal/min)	VOC Emission Factor[1] (lb/10^6 gal)	VOC PTE[2]	
			(lb/hr)	(tons/yr)
EU-6001	10,667	0.7	0.45	1.96
EU-6002	10,667		0.45	1.96
EU-6003	10,667		0.45	1.96
Total			**1.34**	**5.89**

Notes:

1. AP-42, 5th ed., (4/15), Table 5.1-3 controlled emissions - minimization of HC leaks into cooling water and monitoring cooling water for HC.

2. Worst-case PTE assuming all water contacts hydrocarbons, where denominator is 10^6 gal of cooling water that contacts hydrocarbons

Methodology

VOC PTE (lb/hr) = VOC Emission Factor (lb/10^6 gal) x Cell Flow Rate (gal/min) x 60 (min/hr) / 1,000,000 (gal/10^6 gal)

PTE (tons/yr) = PTE (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

3. Ammonia

Unit ID	Cell Flow Rate (gal/min)	Ammonia Emission Factor[1] (mg/l)	Ammonia PTE	
			(lb/hr)	(tons/yr)
EU-6001	10,667	4.26E-03	2.27E-02	0.10
EU-6002	10,667		2.27E-02	0.10
EU-6003	10,667		2.27E-02	0.10
Total			**6.82E-02**	**0.30**

Notes:

1. Provided by the source

Methodology

Ammonia PTE (lb/hr) = Ammonia Emission Factor (mg/l) x Cell Flow Rate (gal/min) x 3.7854 (l/gal) x 2.2046E-06 (lb/mg) x 60 (min/hr)

PTE (tons/yr) = PTE (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

4. Total

	Potential to Emit after Issuance (tons/yr)							
	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO	Ammonia
Cooling tower	0.84	0.48	1.75E-03	-	-	5.89	-	0.30

Methodology

PTE (tons/yr) = PTE (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

Appendix A: Emission Calculations
Emergency Engine Fuel Tanks

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

Evansville Meteorological Data (TANKS 4.0.9d)

Average daily maximum ambient temperature, T_{AX} = 66.3 °F
Average daily minimum ambient temperature, T_{AN} = 45.2 °F
Daily total insolation, I = 1334.94 Btu/ft^2-day
average atmospheric pressure, P_A = 14.558 psia

Table 7.1-6		color	condition
α =	0.17	white	good

EU-6005, Emergency generator diesel fuel tank

Horizontal tank, dimensions of commercially available tank (www.dultmeier.com, model HST2000-64)

V = 2000 gal L = 12.0 ft D = 5.33 ft

Storage Losses (breathing losses)

Daily average ambient temperature, T_{AA} = 515.7 °R, Eqn 1-27, $T_{AA} = (T_{AX} + T_{AN})/2$
Liquid bulk temperature, T_B = 515.7 °R, Eqn 1-28, $T_B = T_{AA} + 6\ \alpha - 1$
Daily average liquid surface temperature, T_{LA} = 517.5 °R, Eqn 1-26, $T_{LA} = 0.44\ T_{AA} + 0.56\ T_B + 0.0079\ \alpha\ I$

Vapor molecular weight, M = 130 lb/lb-mole, Table 7.1-2
Throughput, Q = 69450 gal/yr = 1653.6 bbl/yr *(note 1 bbl = 42 gal)*

A = 12.31 vapor pressure equation (Eqn 1-24) coefficients,
B = 9029.5 regression of data in Table 7.1-2

Vapor pressure at daily average liquid surface temperature, P_{VA} = 0.01 psia, Eqn 1-24, Ch 7

Effective diameter, D_E = 9.03 ft Eqn 1-13, $D_E = ((LD)/(\pi/4))^{1/2}$
Effective height, H_E = 4.19 ft Eqn 1-14, $H_E = \pi D/4$
Vapor space outage, H_{VO} = 2.09 ft $H_E/2$, explanation of terms, Eqn 1-15

Maximum and minimum liquid surface temperature and vapor pressure					
T_{LX} =	528.1 °R	T_{LN} =	507.0 °R	Eqn 1-26 applied at T_{AX} and T_{AN}, note 5 to Eqn 1-7
P_{VX} =	0.01 psia	P_{VN} =	0.00 psia	Eqn 1-24 applied at T_{AX} and T_{AN}, note 5 to Eqn 1-7

Daily vapor pressure range, ΔP_V = 0.00 psia, Eqn 1-9, $\Delta P_V = P_{VX} - P_{VN}$
Daily vapor temperature range, ΔT_V = 21.5 °R, eqn 1-8, $\Delta T_V = 0.72\ (T_{AX} - T_{AN}) + 0.028\ \alpha\ I$
Breather vent pressure setting range, ΔP_B = 0.06 psia, assumed, see note 3 to Eqn 1-7

Vapor space expansion factor, K_E = 0.04 Eqn 1-7, $K_E = (\Delta T_V/T_{LA}) + (\Delta P_V - \Delta P_B)/(P_A - P_{VA})$
Vented vapor saturation factor, K_S = 1.00 Eqn 1-20, $K_S = 1 / (1 + 0.053\ P_{VA}\ H_{VO})$
Stock vapor densiity, W_V = 0.0001 lb/ft^3, Eqn 1-21, $W_V = (M_V\ P_{VA}) / (R\ T_{LA})$
R = ideal gas law constant, 10.73 (psia ft^3)/(lb-mole ºR), Table 1-9, Perry's Chemical Engineers' Handbook, 6th ed.

Storage loss, $L_S = 365\ K_E\ (\pi D_E^2/4)\ H_{VO}\ K_S\ W_V$, Eqn 1-4

L_S = 0.25 lb/yr

Working Losses

turnovers = 35 per year, N = Q (gal/yr) / V (gal) *(note Eqn 1-30 gives N in terms of Q (bbl/yr) and V_{LX} (ft^3), presumed the same as this equation)*
Working loss turnover (saturation) factor, K_N = 1 Fig 7.1-18, explanation of terms, Eqn 1-29
Working loss product factor, K_P = 1 organic liquids other than crude oil, explanation of terms, Eqn 1-29

Working loss, $L_W = 0.0010\ M_V\ P_{VA}\ Q\ K_N\ K_P$, Eqn 1-29

L_W = 1.27 lb/yr, Eqn 1-29, AP-42 Ch 7

Total Losses

Total losses, $L_T = L_S + L_W$, Eqn 1-1

Appendix A: Emission Calculations
Emergency Engine Fuel Tanks

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

EU-6007, Emergency fire pump diesel fuel tank
Horizontal tank, dimensions of commercially available tank (www.dultmeier.com, model HST520-50)

V = 520 gal   L = 5.08 ft   D = 4.17 ft

Storage Losses (breathing losses)

Daily average ambient temperature, T_{AA} = 515.7 °R, Eqn 1-27, $T_{AA} = (T_{AX} + T_{AN})/2$
Liquid bulk temperature, T_B = 515.7 °R, Eqn 1-28, $T_B = T_{AA} + 6\ \alpha - 1$
Daily average liquid surface temperature, T_{LA} = 517.5 °R, Eqn 1-26, $T_{LA} = 0.44\ T_{AA} + 0.56\ T_B + 0.0079\ \alpha\ I$

Vapor molecular weight, M = 130 lb/lb-mole, Table 7.1-2
Throughput, Q = 19950 gal/yr = 475.0 bbl/yr *(note 1 bbl = 42 gal)*

A = 12.31 vapor pressure equation (Eqn 1-24) coefficients,
B = 9029.5 regression of data in Table 7.1-2

Vapor pressure at daily average liquid surface temperature, P_{VA} = 0.01 psia, Eqn 1-24, Ch 7

Effective diameter, D_E = 5.19 ft   Eqn 1-13, $D_E = ((LD)/(\pi/4))^{1/2}$
Effective height, H_E = 3.27 ft   Eqn 1-14, $H_E = \pi D/4$
Vapor space outage, H_{VO} = 1.64 ft $H_E/2$, explanation of terms, Eqn 1-15

Maximum and minimum liquid surface temperature and vapor pressure
T_{LX} = 528.1 °R T_{LN} = 507.0 °R   Eqn 1-26 applied at T_{AX} and T_{AN}, note 5 to Eqn 1-7
P_{VX} = 0.01 psia P_{VN} = 0.00 psia   Eqn 1-24 applied at T_{AX} and T_{AN}, note 5 to Eqn 1-7

Daily vapor pressure range, ΔP_V = 0.00 psia, Eqn 1-9, $\Delta P_V = P_{VX} - P_{VN}$
Daily vapor temperature range, ΔT_V = 21.5 °R, eqn 1-8, $\Delta T_V = 0.72\ (T_{AX} - T_{AN}) + 0.028\ \alpha\ I$
Breather vent pressure setting range, ΔP_B = 0.06 psia, assumed, see note 3 to Eqn 1-7

Vapor space expansion factor, K_E = 0.04 Eqn 1-7, $K_E = (\Delta T_V/T_{LA}) + (\Delta P_V - \Delta P_B)/(P_A - P_{VA})$
Vented vapor saturation factor, K_S = 1.00 Eqn 1-20, $K_S = 1 / (1 + 0.053\ P_{VA}\ H_{VO})$
Stock vapor densiity, W_V = 0.0001 lb/ft^3, Eqn 1-21, $W_V = (M_V\ P_{VA}) / (R\ T_{LA})$
R = ideal gas law constant, 10.73 (psia ft^3)/(lb-mole ºR), Table 1-9, Perry's Chemical Engineers' Handbook, 6th ed.

Storage loss, $L_S = 365\ K_E\ (\pi D_E^2/4)\ H_{VO}\ K_S\ W_V$, Eqn 1-4

L_S = 0.07 lb/yr

Working Losses

turnovers = 38 per year, N = Q (gal/yr) / V (gal) *(note Eqn 1-30 gives N in terms of Q (bbl/yr) and V_{LX} (ft^3), presumed the same as this equation)*
Working loss turnover (saturation) factor, K_N = 0.9486216 Fig 7.1-18, explanation of terms, Eqn 1-29
Working loss product factor, K_P = 1 organic liquids other than crude oil, explanation of terms, Eqn 1-29

Working loss, $L_W = 0.0010\ M_V\ P_{VA}\ Q\ K_N\ K_P$, Eqn 1-29

L_W = 0.35 lb/yr, Eqn 1-29, AP-42 Ch 7

Total Losses

Total losses, $L_T = L_S + L_W$, Eqn 1-1

Potential to Emit			
EU-6005	EU-6007	Total	
1.52	0.41	1.93	lb/yr
7.61E-04	2.06E-04	9.67E-04	tons/yr

Methodology
PTE (lb/yr) = Total losses, L_T
PTE (tons/yr) = PTE (lb/yr) / 2,000 (lb/ton)

Appendix A: Emission Calculations
Large Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. Unrestricted Potential to Emit

	Emergency Generator EU-6006	Fire Pump EU-6008	
Engine Output (HP)	2800	750	
(kW)	2089	560	
Heat Input Capacity (MMBtu/hr)	19.60	5.25	7,000 Btu/HP-hr, ref: note e, AP-42 Table 3.4-3
Maximum Hours Operated per Year	500	500	
Potential Throughput (MMBtu/yr)	9,800	2,625	
Sulfur Content (S) of Fuel (% by weight)	0.0015	0.0015	Sulfur content of fuel limited to 15 ppmw by 40 CFR 60.4207(b)

	Pollutant						
	PM	PM10	direct PM2.5	SO2	NOx	VOC	CO
Emission Factor[1] in lb/HP-hr	-	-	-	1.21E-05	-	-	-
EU-6006 Emission Factors[2] (g/kW-hr)	0.20	0.20	0.20	-	6.40	6.40	3.50
EU-6006 PTE tons/yr	**0.23**	**0.23**	**0.23**	**8.49E-03**	**7.37**	**7.37**	**4.03**
EU-6008 Emission Factors[3] (g/kW-hr)	0.20	0.20	0.20	-	4.00	4.00	3.50
EU-6008 PTE tons/yr	**0.06**	**0.06**	**0.06**	**2.28E-03**	**1.23**	**1.23**	**1.08**
Total	**0.29**	**0.29**	**0.29**	**1.08E-02**	**8.60**	**8.60**	**5.11**

Notes:

1. Table 3.4-1, diesel fuel (SCC 2-02-004-01), AP-42, 5th ed., (October 1996)

2. 40 CFR 60.6202(a)(2), referencing Table 1, 40 CFR 89.112

3. Table 4, 40 CFR 60, Subpart IIII

Methodology

Potential to Emit (tons/yr) = Emission Factor (lb/HP-hr) x Engine Output (HP) x Maximum Hours Operated per Year (hr/yr) / 2,000 (lb/ton) *SO*$_2$
Potential to Emit (tons/yr) = Emission Factor (g/kW-hr) x Engine Output (kW) x Maximum Hours Operated per Year (hr/yr) x 0.0022046 (lb/g) / 2,000 (lb/ton) *others*
Standards applicable under 40 CFR 60, Subpart IIII limit NOx + NMHC, worst case PTE for each pollutant is calculated at the full value of the limit
VOC assumed equal to NMHC (nonmethane hydrocarbons)

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Acetaldehyde	Acrolein	Benzene	Formaldehyde	Toluene	Xylenes	Total PAH HAPs[1]
Emission Factor[2] in lb/MMBtu	2.52E-05	7.88E-06	7.76E-04	7.89E-05	2.81E-04	1.93E-04	2.12E-04
Emerg Gen (EU-6006) PTE tons/yr	1.23E-04	3.86E-05	3.80E-03	3.87E-04	1.38E-03	9.46E-04	1.04E-03
Emerg FWP (EU-6008) PTE tons/yr	3.31E-05	1.03E-05	1.02E-03	1.04E-04	3.69E-04	2.53E-04	2.78E-04
Total	1.57E-04	4.90E-05	4.82E-03	4.90E-04	1.75E-03	1.20E-03	1.32E-03

Notes:

1. Source: Table 3.4-4, AP-42. PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

2. Source: Table 3.4-3, AP-42, except as noted

Potential Emission of Total HAPs (tons/yr)	**9.78E-03**

Methodology

Heat Input Capacity (MMBtu/hr) = Engine Output (HP) x 7,000 (Btu/HP-hr) / 1,000,000 (Btu/MMBtu)
Potential Throughput (MMBtu/hr) = Heat Input Capacity (MMBtu/hr) x Maximum Hours Operated per Year (hr/yr)
Potential to Emit (tons/yr) = Emission Factor (lb/MMBtu) x Potential Throughput (MMBtu/yr) /2,000 (lb/ton)

Green House Gas Emissions (GHG)

	Pollutant				CO$_2$e Compliance Determination Factor (tons/hr)
	CO2	CH4	N2O	CO$_2$e	
Emission Factor in lb/MMBtu	165	8.10E-03	1.32E-03	-	-
Emerg Gen (EU-6006) PTE tons/yr	809	3.97E-02	6.48E-03	811	1.62
Emerg FWP (EU-6008) PTE tons/yr	217	1.06E-02	1.74E-03	217	0.43
Total				1,029	

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.
CH4 and N2O Emission Factor from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).
GHG compliance determination factor (tons CO$_2$e/MMCF fuel gas) = CO$_2$e Total (tons/yr) / Potential Throughput (MMCF/yr)

Appendix A: Emission Calculations
Large Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

2. Potential to Emit After Issuance

	Emergency Generator EU-6006	Fire Pump EU-6008	
Engine Output (HP)	2800	750	
(kW)	2089	560	
Heat Input Capacity (MMBtu/hr)	19.60	5.25	7,000 Btu/HP-hr, ref: note e, AP-42 Table 3.4-3
Limited Hours Operated per Year	100	200	
Limited Throughput (MMBtu/yr)	1,960	1,050	
Sulfur Content (S) of Fuel (% by weight)	0.0015	0.0015	Sulfur content of fuel limited to 15 ppmw by 40 CFR 60.4207(b)

	Pollutant						
	PM	PM10	direct PM2.5	SO2	NOx	VOC	CO
Emission Factor[1] in lb/HP-hr	-	-	-	1.21E-05	-	-	-
EU-6006 Emission Factors[2] (g/kW-hr)	0.20	0.20	0.20	-	6.40	6.40	3.50
EU-6006 PTE tons/yr	0.05	0.05	0.05	1.70E-03	1.47	1.47	0.81
EU-6008 Emission Factors[3] (g/kW-hr)	0.20	0.20	0.20	-	4.00	4.00	3.50
EU-6008 PTE tons/yr	0.02	0.02	0.02	9.10E-04	0.49	0.49	0.43
Total	0.07	0.07	0.07	2.61E-03	1.97	1.97	1.24

Notes:
1. Table 3.4-1, diesel fuel (SCC 2-02-004-01), AP-42, 5th ed., (October 1996)
2. 40 CFR 60.6202(a)(2), referencing Table 1, 40 CFR 89.112
3. Table 4, 40 CFR 60, Subpart IIII

Methodology
Potential to Emit (tons/yr) = Emission Factor (lb/HP-hr) x Engine Output (HP) x Maximum Hours Operated per Year (hr/yr) / 2,000 (lb/ton) *SO_2*
Potential to Emit (tons/yr) = Emission Factor (g/kW-hr) x Engine Output (kW) x Maximum Hours Operated per Year (hr/yr) x 0.0022046 (lb/g) / 2,000 (lb/ton) *others*
Standards applicable under 40 CFR 60, Subpart IIII limit NOx + NMHC, worst case PTE for each pollutant is calculated at the full value of the limit
VOC assumed equal to NMHC (nonmethane hydrocarbons)

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Acetaldehyde	Acrolein	Benzene	Formaldehyde	Toluene	Xylenes	Total PAH HAPs[1]
Emission Factor[2] in lb/MMBtu	2.52E-05	7.88E-06	7.76E-04	7.89E-05	2.81E-04	1.93E-04	2.12E-04
Emerg Gen (EU-6006) PTE tons/yr	1.23E-04	3.86E-05	3.80E-03	3.87E-04	1.38E-03	9.46E-04	1.04E-03
Emerg FWP (EU-6008) PTE tons/yr	3.31E-05	1.03E-05	1.02E-03	1.04E-04	3.69E-04	2.53E-04	2.78E-04
Total	1.57E-04	4.90E-05	4.82E-03	4.90E-04	1.75E-03	1.20E-03	1.32E-03

Notes:
1. Source: Table 3.4-4, AP-42. PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
2. Source: Table 3.4-3, AP-42, except as noted

Potential Emission of Total HAPs (tons/yr)	**9.78E-03**

Methodology
Heat Input Capacity (MMBtu/hr) = Engine Output (HP) x 7,000 (Btu/HP-hr) / 1,000,000 (Btu/MMBtu)
Potential Throughput (MMBtu/hr) = Heat Input Capacity (MMBtu/hr) x Maximum Hours Operated per Year (hr/yr)
Potential to Emit (tons/yr) = Emission Factor (lb/MMBtu) x Potential Throughput (MMBtu/yr) /2,000 (lb/ton)

Green House Gas Emissions (GHG)

	Pollutant				CO_2e Compliance Determination Factor (tons/hr)
	CO2	CH4	N2O	CO_2e	
Emission Factor in lb/MMBtu	165	8.10E-03	1.32E-03	-	-
Emerg Gen (EU-6006) PTE tons/yr	162	7.94E-03	1.30E-03	162	1.62
Emerg FWP (EU-6008) PTE tons/yr	87	4.25E-03	6.94E-04	87	0.43
Total				249	

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.
CH4 and N2O Emission Factor from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).
GHG compliance determination factor (tons CO_2e/MMCF fuel gas) = CO_2e Total (tons/yr) / Potential Throughput (MMCF/yr)

Appendix A: Emission Calculations
Block 6500 Lime Handling & Storage

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. Uncontrolled Potential to Emit

Description	Control Device ID	Silo Throughput[1] (tons/hr)	Uncontrolled					
			Emission Factor		Potential to Emit			
			PM (lb/ton)	PM10 = PM2.5 (lb/ton)	PM (lb/hr)	PM10 = PM2.5 (lb/hr)	PM (tons/yr)	PM10 = PM2.5 (tons/yr)
Lime truck unloading[2]	EU-6501	20.00	3.14	1.1	62.80	22.00	275.06	96.36
Total[3]							275.06	96.36

Notes:

1. Silo throughput assumed equal to unloading one truck per hour. Throughput for lime transfer assumed the same as a worst case.

2. Emission factor source: cement supplement unloading to elevated storage silo (pneumatic) (SCC 3-05-011-17), Table 11.12-2, AP-42, 5th ed., June 2006

3. Expected lime demand is 830 tons per year, however, this value is not considered a bottleneck because there is no physical limitation on the lime softening process.

Methodology

Potential to Emit (lb/hr) = Silo Throughput (tons/hr) x Emission Factor (lb/ton)

Potential to Emit (tons/yr) = Potential to Emit (lb/hr) x 8,760 (hrs/yr) / 2,000 (lb/ton)

2. Potential to Emit After Issuance

	Unit	Air Flow Rate (dscfm)	Pollutant		
			PM	PM_{10}	direct $PM_{2.5}$
Emissions Limitation[1] (gr/dscf)	EU-6501	556	0.002	0.002	0.002
Potential to Emit After Issuance (lb/hr)			0.01	0.01	0.01
Potential to Emit After Issuance (tons/yr)			0.04	0.04	0.04
Total			**0.04**	**0.04**	**0.04**

Notes:

1. BACT specifications

2. Assumes 20 ton/hr as used in section 1.

Methodology

PTE After Issuance (tons/yr) = Air Flow Rate (dscfm) x Emissions Limitation (gr/dscf) x 60 (min/hr) / 7,000 (gr/lb) x 8,760 hr/yr) / 2,000 (lb/ton) *unloading*

PTE After Issuance (tons/yr) = Silo Throughput (tons/hr) x Emission Factor (lb/ton) x 8,760 (hr/yr) / 2,000 (lb/ton) *transfer*

Appendix A: Emission Calculations
Natural Gas Combustion Only
MMBTU/HR >100
Hydrogen Plant Reformers 1 and 2

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. Unrestricted Potential to Emit

A. Deaeration vent

		Production Capacity		Emission Factor (lb/ton)[1]			Potential to Emit	
				VOC	CO	CO_2	VOC	
		(tons/day)	(tons/hr)				(lb/hr)	(tons/yr)
Hydrogen Plant 1 DA vent	EU-7003	279.00	11.63	0.28	0.09	21.21	3.20	14.02
Hydrogen Plant 2 DA vent	EU-7004	279.00	11.63	0.28	0.09	21.21	3.20	14.02
Total								**28.03**

		Potential to Emit					
		HAP[2]		CO		CO_2[3]	
		(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
Hydrogen Plant 1 DA vent	EU-7003	2.95	12.91	1.06	4.64	246.58	1080.00
Hydrogen Plant 2 DA vent	EU-7004	2.95	12.91	1.06	4.64	246.58	1080.00
Total			**25.82**		**9.29**		**2160.00**

Notes:

1. Emission factor provided by the source

2. 92.1 wt% of VOC in deaeration vent is methanol, which is a HAP.

3. CO_2 emission factor provided by the source, from material balance calculations.

B. Steam Reforming Reaction

		Heat Input Capacity MMBtu/hr	Fuel Gas HHV MMBtu/MMCF
EU-7001	Reformer 1	838.6	1009
EU-7002	Reformer 2	838.6	
Total		1677.2	

	Pollutant						
Vendor Data	PM	PM_{10}	direct $PM_{2.5}$	SO_2[1]	NOx	VOC	CO
Emission Factor in lb/MMBtu	0.006	0.006	0.006	--	0.065	0.006	0.02
Reformer 1 PTE in tons/yr	22.04	22.04	22.04	5.20	238.75	22.04	73.46
Reformer 2 PTE in tons/yr	22.04	22.04	22.04	5.20	238.75	22.04	73.46
Total PTE (ton/yr)	44.08	44.08	44.08	10.40	477.50	44.08	146.92
Control Efficiency	-	-	-		0.90	-	-
Reformer 1 Controlled Emissions (ton/yr)	22.04	22.04	22.04	5.20	23.87	22.04	73.46
Reformer 2 Controlled Emissions (ton/yr)	22.04	22.04	22.04	5.20	23.87	22.04	73.46
Total PTE (ton/yr)	44.08	44.08	44.08	10.40	47.75	44.08	146.92

Notes:

1. BACT specification of 25 ppmv H_2S in fuel gas taken as a worst case. Fuel gas supplied to reformers must be treated to remove sulfur because it is a catalyst poison.

Methodology

Emission Factors provided by vendor based on similar unit at another plant.
PTE (ton/yr) = Heat Input Capacity (MMBtu/hr) x emission factor (lb/MMBtu) x 8760 hr/yr x 1 ton/2000 lb

Appendix A: Emission Calculations
Natural Gas Combustion Only
MMBTU/HR >100
Hydrogen Plant Reformers 1 and 2

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

C. Total of all Operations

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Unrestricted PTE (ton/yr)	**44.08**	**44.08**	**44.08**	**10.40**	**477.50**	**72.11**	**146.92**
PTE After Controls(ton/yr)	**44.08**	**44.08**	**44.08**	**10.40**	**47.75**	**72.11**	**146.92**

Greenhouse Gases (GHGs) Both Reformers

	Greenhouse Gas		
	CO_2[1]	CH_4[2]	N_2O[1]
Emission Factor in lb/MMBtu	268	2.25E-03	6.27E-04
Potential Emission in tons/yr	1,970,755	16.6	4.6
Summed Potential Emissions in tons/yr	1,970,776		
CO2e Total in tons/yr	1,972,542		

Notes:

1. Emission factor from equipment supplier, provided by the source

2. Emission factors for natural gas combustion, expressed in lb/MMBtu using natural gas HHV of 1,020 MMBtu/MMCF

Methodology

The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

2. Potential to Emit After Issuance

A. Deaeration vent		Potential to Emit			CO_2e Compliance Determination Factor (tons/hr)
		VOC (tons/yr)	HAP (tons/yr)	CO_2 (tons/yr)	
Hydrogen Plant 1 DA vent	EU-7003	14.02	12.91	1,080	0.12
Hydrogen Plant 2 DA vent	EU-7004	14.02	12.91	1,080	0.12
Total		**28.03**	**25.82**	**2,160**	

Methodology

GHG Compliance Determination Factor (tons CO_2e/hr) = CO_2 Emission Factor (lb/ton H_2) x Production Capacity (tons H_2/hr) / 2,000 (lb/ton)

Appendix A: Emission Calculations
Natural Gas Combustion Only
MMBTU/HR >100
Hydrogen Plant Reformers 1 and 2

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

B. Steam Reforming Reaction

	Pollutant								CO_2e Compliance Determination Factor (tons/hr)
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO	CO_2e	
Emission Limit (gr/scf) (as S)[1]	-	-	-	0.005	-	-	-	-	
Emission Limit (lb/MMBtu)[1]	0.0060	0.0060	0.0048	0.0014	0.0065	0.0015	0.020	269	-
Reformer 1 PTE (lb/hr)	5.03	5.03	4.03	1.19	5.45	1.26	16.77	225,176	112.59
Reformer 1 PTE (tons/yr)	22.04	22.04	17.63	5.20	23.87	5.51	73.46	986,271	
Reformer 2 PTE (lb/hr)	5.03	5.03	4.03	1.19	5.45	1.26	16.77	225,176	112.59
Reformer 2 PTE (tons/yr)	22.04	22.04	17.63	5.20	23.87	5.51	73.46	986,271	
Total PTE (ton/yr)	**44.08**	**44.08**	**35.26**	**10.40**	**47.75**	**11.02**	**146.92**	**1,972,542**	

Notes:

1. BACT Required Design Specifications

Methodology

SO_2 Emission Limit (lb/MMBtu) = Emission Limit (0.005 gr/scf as S) / 7,000 (gr/lb) x 1,000,000 (scf/MMCF) / HHV (MMBtu/MMCF) x 64 lb SO_2/lb mole / 32 lb S/lb mole

PTE (lb/hr) = Emission Limit (lb/MMBtu) x Heat Input Capacity (MMBtu/hr)

PTE (tons/yr) = PTE (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

GHG Compliance Determination Factor (tons CO_2e/hr) = CO_2e PTE (tons/yr) / 8,760 (hr/yr)

C. Total of all Operations

	Pollutant							
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO	CO_2e
Total PTE (ton/yr)	**44.08**	**44.08**	**35.26**	**10.40**	**47.75**	**39.05**	**156.21**	**1,974,702**
GHG Compliance Determination Factor (tons CO_2e/hr) *sum of DA vent and reformer* =								112.71

Appendix A: Emission Calculations
Wastewater Treatment

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. Uncontrolled Potential to Emit

Emission Point ID	Description	Uncontrolled Potential To Emit[1] (lb/hr)	
		VOC	HAP
EU-8001	Bio-reactor exhaust	9.300	1.38E+00
EU-8002	Oily water sump	0.075	0
EU-8003	Manhole No. 1	0.025	0
Total	**lb/hr**	**9.40**	**1.38**
	tons/yr	**41.17**	**6.04**

Notes:

1. Calculated from PTE After Issuance using the control efficiency for oil-water separators in petroleum refinery service (96%) from Table 5.1-3, AP-42, April 2015.

Methodology

PTE (lb/hr) = Potential to Emit After Issuance (lb/hr) / (1 - 96%/100)
PTE (tons/yr) = PTE (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

2. Potential to Emit After Issuance

Emission Point ID	Description	Exhaust Flow (acfh)	Concentration[1] (ppmvd)		Potential to Emit After Issuance[2] (lb/hr)	
			VOC	HAP	VOC	HAP
EU-8001	Bio-reactor exhaust	96,658	20	3	0.372	5.52E-02
EU-8002	Oily water sump	670	20	0	0.003	0
EU-8003	Manhole No. 1	268	20	0	0.001	0
Total				**lb/hr**	**0.376**	**5.52E-02**
				tons/yr	**1.65**	**0.24**

Notes:

1. Exhaust VOC concentration of 20 ppmvd is deterined to be BACT.

2. Potential to Emit (lb/hr) provided by the source

Methodology

PTE (tons/yr) = PTE (lb/hr) x 8,760 (hr/yr) / 2,000 (lb/ton)

Appendix A: Emissions Calculations
VOC/HAPs Fugitive Leaks

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

1. VOC

					Block 2000			Block 4000		
Fugitive Equipment	Physical Service	Emisssion Factor[1] (NMOC taken as VOC) (kg/hr/source)	(lb/hr/source)	Control Efficiency[2] %	count	VOC PTE (tons/yr)	Controlled VOC (tons/yr)	count	VOC PTE (tons/yr)	Controlled VOC (tons/yr)
Valves	Gas	0.0268	0.059	70%	3	0.8	0.2	0	0.0	0.0
	Light liquid	0.0109	0.024	61%	32	3.4	1.3	34	3.6	1.4
	Heavy liquid	0.00023	0.001		153	0.3	0.3	0	0.0	0.0
Pump seals	Light liquid	0.114	0.251	45%	18	19.8	10.9	4	4.4	2.4
	Heavy liquid	0.021	0.046		19	3.9	3.9	0	0.0	0.0
Flanges/connectors	All	0.00025	0.00055		1036	2.5	2.5	141	0.3	0.3
Pressure Relief Valves[3]	Gas	0.16	0.353	70%	19	29.4	8.8	0	0.0	0.0
	Liquid	0.16	0.353	61%	90	139.1	54.2	0	0.0	0.0
Compressor seals	Gas	0.636	1.402	0%	1	6.1	6.1	3	18.4	18.4
Open-Ended Lines/Valves[4]	All	0.023	0.051	100%	90	20.0	0.0	4	0.9	0.0
Sampling Connections[5]	all	0.015	0.033	100%	205	29.7	0.0	8	1.2	0.0
Water Seal Process Drains[6]	all		0.07	0%	205	62.9	62.9	8	2.5	2.5
Total	-		-			**317.8**	**151.18**		**31.3**	**25.04**

Notes:

1. Emission factor source *Protocol for Equipment Leak Emission Estimates**, EPA-453/R-95-017, November 1995), Table 2-2 (Refinery), except as noted.*

2. Control efficiency source *Protocol for Equipment Leak Emission Estimates**, EPA-453/R-95-017, November 1995), Table 5-3, except as noted.*

3. Source gives an emission factor for PRVs only in gas service, presumed the same for liquid service as a worst case.

4. Table 5-1 gives control efficiency of 100% for blind, cap, plug, or second valve.

5. Table 5-1 gives control efficiency of 100% for closed loop sampling.

6. "Emission Factors for Equipment Leak Fugitive Components", Addendum to RG-360A, Texas DEQ, January 2008,
https://www.tceq.texas.gov/assets/public/implementation/air/ie/pseiforms/ef_elfc.pdf

2. Hazardous Air Pollutants

HAP	Weight Percent[1] %	Potential to Emit Uncontrolled (tons/yr)	After Issuance (tons/yr)
Benzene	1.50%	5.24	2.64
o-cresol	0.12%	0.42	0.21
m- & *p-* cresol	0.05%	0.17	8.81E-02
n-Hexane	4.00%	13.96	7.05
Phenol	0.05%	0.17	8.81E-02
Toluene	4.00%	13.96	7.05
Xylenes	5.00%	17.45	8.81
Total	14.72%	**51.38**	**25.94**

Notes:

1. HAP weight percentages from licensor historical data, provided by the source

3. Totals

	TOTAL FUGITIVES Uncontrolled	After Issuance	
VOC	**349.0**	**176.2**	**ton/yr**
HAPs	**51.4**	**25.9**	**ton/yr**

Methodology

Emission Factor (lb/hr/source) = Emission Factor (kg/hr/source) x 2.205 (lb/kg)

VOC PTE (ton/yr) = Emission factor (lb/hr/source) x number of components (count) x 8,760 (hr/yr) / 2,000 (lb/ton)

HAP (ton/yr) = VOC PTE (ton/yr) x HAP wt%

Appendix A: Emission Calculations
Fugitive Dust Emissions - Paved Roads

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

Paved Roads at Industrial Site

The following calculations determine the amount of emissions created by paved roads, based on 8,760 hours of use and AP-42, Ch 13.2.1 (1/2011).

Vehicle Informtation (provided by source)

Type	Maximum number of vehicles per day	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight Loaded (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Na2S delivery (entering plant)	9.32E-02	1.0	0.1	40.0	3.7	2133	0.404	0.0	13.7
Na2S delivery (leaving plant)	9.32E-02	1.0	0.1	15.0	1.4	2133	0.404	0.0	13.7
aniline delivery (entering plant)	1.37E-03	1.0	0.0	40.0	0.1	1640	0.311	0.0	0.2
aniline delivery (leaving plant)	1.37E-03	1.0	0.0	15.0	0.0	1640	0.311	0.0	0.2
DMDS delivery (entering plant)	2.74E-03	1.0	0.0	40.0	0.1	1640	0.311	0.0	0.3
DMDS delivery (leaving plant)	2.74E-03	1.0	0.0	15.0	0.0	1640	0.311	0.0	0.3
amine delivery (entering plant)	3.29E-02	1.0	0.0	40.0	1.3	1804	0.342	0.0	4.1
amine delivery (leaving plant)	3.29E-02	1.0	0.0	15.0	0.5	1804	0.342	0.0	4.1
ammonia loading (entering plant)	0.16	1.0	0.2	15.0	2.5	2953	0.559	0.1	33.6
ammonia loading (leaving plant)	0.16	1.0	0.2	40.0	6.6	2953	0.559	0.1	33.6
sulfur loading[1] (entering plant)	9.00	1.0	9.0	15.0	135.0	984	0.186	1.7	612.2
sulfur loading (leaving plant)	9.00	1.0	9.0	40.0	360.0	984	0.186	1.7	612.2
residue loading[1] (entering plant)	62.00	1.0	62.0	15.0	930.0	984	0.186	11.6	4217.4
residue loading (leaving plant)	62.00	1.0	62.0	40.0	2480.0	984	0.186	11.6	4217.4
sulfuric acid delivery (entering plant)	0.14	1.0	0.1	40.0	5.7	820	0.155	0.0	8.1
sulfuric acid delivery (leaving plant)	0.14	1.0	0.1	15.0	2.1	820	0.155	0.0	8.1
caustic delivery (entering plant)	0.14	1.0	0.1	40.0	5.7	820	0.155	0.0	8.1
caustic delivery (leaving plant)	0.14	1.0	0.1	15.0	2.1	820	0.155	0.0	8.1
boiler chemicals delivery (entering plant)	0.14	1.0	0.1	40.0	5.7	820	0.155	0.0	8.1
boiler chemicals delivery (leaving plant)	0.14	1.0	0.1	15.0	2.1	820	0.155	0.0	8.1
diesel fuel delivery (entering plant)	0.14	1.0	0.1	40.0	5.7	820	0.155	0.0	8.1
diesel fuel delivery (leaving plant)	0.14	1.0	0.1	15.0	2.1	820	0.155	0.0	8.1
lime delivery (entering plant)	0.14	1.0	0.1	40.0	5.7	1312	0.248	0.0	12.9
lime delivery (leaving plant)	0.14	1.0	0.1	15.0	2.1	1312	0.248	0.0	12.9
water chemicals delivery (entering plant)	0.14	1.0	0.1	40.0	5.7	1312	0.248	0.0	12.9
water chemicals delivery (leaving plant)	0.14	1.0	0.1	15.0	2.1	1312	0.248	0.0	12.9
lime sludge loading (entering plant)	0.14	1.0	0.1	15.0	2.1	1312	0.248	0.0	12.9
lime sludge loading (leaving plant)	0.14	1.0	0.1	40.0	5.7	1312	0.248	0.0	12.9
WWT chemicals delivery (entering plant)	0.14	1.0	0.1	40.0	5.7	1640	0.311	0.0	16.2
WWT chemicals delivery (leaving plant)	0.14	1.0	0.1	15.0	2.1	1640	0.311	0.0	16.2
WWT sludge loading (entering plant)	0.14	1.0	0.1	15.0	2.1	1640	0.311	0.0	16.2
WWT sludge sludge loading (leaving plant)	0.14	1.0	0.1	40.0	5.7	1640	0.311	0.0	16.2
Notes:		**Totals**	**145.2**		**3991.7**			**27.3**	**9969.7**

1. Sulfur and residue will ship by rail. As a worst-case estimate, truck shipments totaling 5% of the annual production are included in road fugitives calculations.

Average Vehicle Weight Per Trip =	27.5	tons/trip
Average Miles Per Trip =	0.19	miles/trip

Unmitigated Emission Factor, Ef = [k * (sL)^0.91 * (W)^1.02] (Equation 1 from AP-42 13.2.1)

	PM	PM10	PM2.5	
where k =	0.011	0.0022	0.00054	lb/VMT = particle size multiplier (AP-42 Table 13.2.1-1)
W =	27.5	27.5	27.5	tons = average vehicle weight (provided by source)
sL =	9.7	9.7	9.7	g/m^2 = silt loading (worst-case value for paved roads at iron and steel production facilities - Table 13.2.1-3)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [1 - (p/4N)] (Equation 2 from AP-42 13.2.1)

Mitigated Emission Factor, Eext = Ef * [1 - (p/4N)]

where p =	120	days of rain greater than or equal to 0.01 inches (see Fig. 13.2.1-2)
N =	365	days per year

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	2.555	0.511	0.1255	lb/mile
Mitigated Emission Factor, Eext =	2.345	0.469	0.1151	lb/mile
Dust Control Efficiency =	90%	90%	90%	(pursuant to control measures outlined in fugitive dust control plan)

Appendix A: Emission Calculations
Fugitive Dust Emissions - Paved Roads

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

Process	Mitigated PTE of PM (tons/yr)	Mitigated PTE of PM10 (tons/yr)	Mitigated PTE of PM2.5 (tons/yr)	Controlled PTE of PM (tons/yr)	Controlled PTE of PM10 (tons/yr)	Controlled PTE of PM2.5 (tons/yr)
Na2S delivery (entering plant)	0.02	0.00	0.00	0.00	0.00	0.00
Na2S delivery (leaving plant)	0.02	0.00	0.00	0.00	0.00	0.00
aniline delivery (entering plant)	0.00	0.00	0.00	0.00	0.00	0.00
aniline delivery (leaving plant)	0.00	0.00	0.00	0.00	0.00	0.00
DMDS delivery (entering plant)	0.00	0.00	0.00	0.00	0.00	0.00
DMDS delivery (leaving plant)	0.00	0.00	0.00	0.00	0.00	0.00
amine delivery (entering plant)	0.00	0.00	0.00	0.00	0.00	0.00
amine delivery (leaving plant)	0.00	0.00	0.00	0.00	0.00	0.00
ammonia loading (entering plant)	0.04	0.01	0.00	0.00	0.00	0.00
ammonia loading (leaving plant)	0.04	0.01	0.00	0.00	0.00	0.00
sulfur loading (entering plant)	0.72	0.14	0.04	0.07	0.01	0.00
sulfur loading (leaving plant)	0.72	0.14	0.04	0.07	0.01	0.00
residue loading (entering plant)	4.95	0.99	0.24	0.49	0.10	0.02
residue loading (leaving plant)	4.95	0.99	0.24	0.49	0.10	0.02
sulfuric acid delivery (entering plant)	0.01	0.00	0.00	0.00	0.00	0.00
sulfuric acid delivery (leaving plant)	0.01	0.00	0.00	0.00	0.00	0.00
caustic delivery (entering plant)	0.01	0.00	0.00	0.00	0.00	0.00
caustic delivery (leaving plant)	0.01	0.00	0.00	0.00	0.00	0.00
boiler chemicals delivery (entering plant)	0.01	0.00	0.00	0.00	0.00	0.00
boiler chemicals delivery (leaving plant)	0.01	0.00	0.00	0.00	0.00	0.00
diesel fuel delivery (entering plant)	0.01	0.00	0.00	0.00	0.00	0.00
diesel fuel delivery (leaving plant)	0.01	0.00	0.00	0.00	0.00	0.00
lime delivery (entering plant)	0.02	0.00	0.00	0.00	0.00	0.00
lime delivery (leaving plant)	0.02	0.00	0.00	0.00	0.00	0.00
water chemicals delivery (entering plant)	0.02	0.00	0.00	0.00	0.00	0.00
water chemicals delivery (leaving plant)	0.02	0.00	0.00	0.00	0.00	0.00
lime sludge loading (entering plant)	0.02	0.00	0.00	0.00	0.00	0.00
lime sludge loading (leaving plant)	0.02	0.00	0.00	0.00	0.00	0.00
WWT chemicals delivery (entering plant)	0.02	0.00	0.00	0.00	0.00	0.00
WWT chemicals delivery (leaving plant)	0.02	0.00	0.00	0.00	0.00	0.00
WWT sludge loading (entering plant)	0.02	0.00	0.00	0.00	0.00	0.00
WWT sludge sludge loading (leaving plant)	0.02	0.00	0.00	0.00	0.00	0.00
Totals	**11.69**	**2.34**	**0.57**	**1.17**	**0.23**	**0.06**

Methodology

Total Weight driven per day (ton/day) = [Maximum Weight Loaded (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Unmitigated PTE (tons/yr) = [Maximum one-way miles (miles/yr)] * [Unmitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (tons/yr) = [Maximum one-way miles (miles/yr)] * [Mitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Controlled PTE (tons/yr) = [Mitigated PTE (tons/yr)] * [1 - Dust Control Efficiency]

Abbreviations

PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particle Matter (<2.5 um)
PTE = Potential to Emit

Appendix A: Emission Calculations
HAP Content of Product Vapor

Company Name: Riverview Energy Corporation
Source Address: 4704 E 2000 N, Dale, IN 47523
Part 70 Permit No.: 147-39554-00065
Reviewer: Doug Logan
Date: 10/19/2018

	HAP as Weight Fraction of VOC						
HAP	Benzene	o-Cresol	m- & p-Cresol	n-Hexane	Phenol	Toluene	Xylenes
CASRN	71-43-2	95-48-7	-	110-54-3	108-95-2	108-88-3	1330-20-7
Naphtha	2.21E-02	9.28E-06	1.60E-06	1.03E-01	3.70E-06	1.89E-02	6.86E-03
Diesel	1.54E-02	1.61E-05	6.67E-06	0	1.55E-05	4.94E-03	4.30E-03

These values are for storage tanks or loading racks, not for equipment leaks where all of the VOC evaporates

Vapor pressure determined at T = 537.97 °R, maximum monthly average for Evansville from meterological data in TANKS, ver 4.0.9d

Blend name components	Molecular Weight M (lb/lb-mole)	Liquid Weight Fraction[1] m	m/M	Liquid Mole Fraction x (m/M) / Σ(m/M)	August Coefficients[2] (AP-42, Chap 7, Eqn 1-24) A	B (°R^{-1})	Vapor Pressure at T P^{sat} P^{sat}=exp(A-B/T) (psia)	Partial Pressure p_i $p_i = xP^{sat}$ (psia)	Vapor Mole Fraction[3] y p_i / 14.7	yM	Vapor Weight Fraction[4] v (yM) / Σ(yM) (as VOC)
Naphtha [5]	91.6				14.51	7,720	1.17				
naphtha fraction[6]	91	0.85	9.33E-03	0.85	-	-	-	0.98	6.69E-02	6.12	8.49E-01
Benzene	78	1.50E-02	1.92E-04	0.02	16.20	8,427	1.71	3.00E-02	2.04E-03	0.16	2.21E-02
o-Cresol	108	1.20E-03	1.11E-05	0.00	16.30	11,307	8.94E-03	9.10E-06	6.19E-07	6.68E-05	9.28E-06
m- & p-Cresol[7]	108	5.00E-04	4.63E-06	0.00	17.09	12,209	3.70E-03	1.57E-06	1.07E-07	1.15E-05	1.60E-06
n-Hexane	86	4.00E-02	4.65E-04	0.04	14.61	7,273	2.97	0.13	8.62E-03	0.74	1.03E-01
Phenol	94	5.00E-04	5.32E-06	0.00	17.42	11,930	8.56E-03	4.17E-06	2.84E-07	2.67E-05	3.70E-06
Toluene	92	4.00E-02	4.35E-04	0.04	14.68	8,220	0.55	2.18E-02	1.48E-03	0.14	1.89E-02
Xylenes	106	5.00E-02	4.72E-04	0.04	14.79	8,945	0.16	6.85E-03	4.66E-04	4.94E-02	6.86E-03
average vapor molecular weight	90.55										
Diesel [8]	198.7				12.31	9,029	0.01				
diesel fraction[9]	199	0.999	5.03E-03	9.99E-01	-	-	-	1.08E-02	7.35E-04	0.15	9.75E-01
Benzene	78	1.00E-04	1.28E-06	2.55E-04	16.20	8,427	1.71	4.35E-04	2.96E-05	2.31E-03	1.54E-02
o-Cresol	108	2.00E-05	1.85E-07	3.68E-05	16.30	11,307	8.94E-03	3.29E-07	2.24E-08	2.42E-06	1.61E-05
m- & p-Cresol[7]	108	2.00E-05	1.85E-07	3.68E-05	17.09	12,209	3.70E-03	1.36E-07	9.25E-09	9.99E-07	6.67E-06
n-Hexane	86	0	0	0	14.61	7,273	2.97	0	0	0	0
Phenol	94	2.00E-05	2.13E-07	4.23E-05	17.42	11,930	8.56E-03	3.62E-07	2.46E-08	2.31E-06	1.55E-05
Toluene	92	1.00E-04	1.09E-06	2.16E-04	14.68	8,220	0.55	1.18E-04	8.04E-06	7.40E-04	4.94E-03
Xylenes	106	3.00E-04	2.83E-06	5.62E-04	14.79	8,945	0.16	8.92E-05	6.07E-06	6.43E-04	4.30E-03
average vapor molecular weight	192.39										

Notes:

1. *HAP fractions from licensor historical data, provided by the source*
2. *Coefficients determined by regression of data in Tbl 3-8, Perry's Chemical Engineers' Handbook, 6th ed., except as noted.*
3. *Vapor mole fraction in air at standard pressure.*
4. *Vapor weight fraction as the fraction of total VOC.*
5. *Product naphtha liquid molecular weight provided by the source from process modeling, 7/26/2018. Vapor pressure coefficients determined by regression of model values provided by the source, 7/27/2018.*
6. *Molecular weight determined by solving iteratively for ΣxM = product naphtha value above. Fraction partial pressure taken as mixture vapor pressure minus the sum of HAP partial pressures.*
7. *Worst-case (highest) vapor pressure (m-cresol)*
8. *Diesel molecular weight provided by the source from process modeling, 7/26/2018. Vapor pressure coefficients determined by regression of data in AP-42, Table 7.1-2 for No 2 distillate fuel oil.*
9. *Molecular weight determined by solving iteratively for ΣxM = product diesel value above. Fraction partial pressure taken as mixture vapor pressure minus the sum of HAP partial pressures.*

Methodology

$x = (m/M) / \Sigma (m/M)$
$P^{sat} = \exp(A-B/T)$, T taken to be 517.7°R
$p = x P^{sat}$, derived from Raoult's Law
$y = p / P_{tot}$ (Dalton's Law, Ptot = 14.7 psia)
$v = (yM) / \Sigma (yM)$, expressed as weight fraction of VOC
average vapor molecular weight = $\Sigma(yM) / \Sigma y$

Indiana Department of Environmental Management
Office of Air Quality

Appendix B – BACT Analysis
Technical Support Document (TSD)
for a PSD/New Source Construction and Part 70 Operating Permit

Source Description and Location

Source Name:	**Riverview Energy Corporation**
Source Location:	**4702 E 2000 N, Dale, IN 47523**
County:	**Spencer**
SIC Code:	**2911 (Petroleum Refining), 2999 (Products of Petroleum and Coal, Not Elsewhere Classified)**
Operation Permit No.:	**T 147-39554-00065**
Permit Reviewer:	**Douglas Logan, P.E.**

Background Information

On January 25, 2018, the Office of Air Quality (OAQ) received an application from Riverview Energy Corporation related to the construction and operation of a new stationary direct coal hydrogenation plant.

This proposed plant will use a Veba Combi Cracker (VCC) process to produce premium distillate products, such as ultra-low sulfur diesel fuel. The VCC technology is a thermal hydrocracking/ hydrogenation process for converting raw coal at very high conversion rates and liquid yields into directly marketable distillates. The feedstock is slurried with finely ground coal, additive and catalyst and then is injected into the high pressure section of the process. After adding makeup hydrogen, the feed stream is preheated by heat recovery from the reactor effluents and fired heater. This feed mixture is converted in a cascade of three slurry phase reactors.

The converted coal, the additive and catalyst are separated from the vaporized reaction products and the recycle gas in a hot separator. The hot separator bottom product is fed to a vacuum flasher for additional distillate recovery. The hydrotreating stage is a single reactor vessel with three beds for hydrotreating, followed by two beds for hydrocracking to maximize diesel production. After leaving the hydrotreating stage the effluent is cooled, condensed and separated from the non-condensable gas fraction and the liquids are processed in a fractionator to produce high quality naphtha, ultra-low sulfur diesel fuel and fractionator bottoms. The bottoms are recycled back to the hydrotreating stage and converted to diesel.

Requirement for Best Available Control Technology (BACT)

326 IAC 2-2 requires a best available control technology (BACT) review to be performed on the proposed new emission units because the potential to emit of at least one pollutant is greater than the PSD major thresholds. The potential to emit of PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, VOC, CO, H_2SO_4, and GHGs is greater than PSD thresholds for these pollutants, therefore a BACT evaluation for these pollutants will be conducted.

Proposed New Emission Units

326 IAC 2-2 (Prevention of Significant Deterioration) requires a BACT analysis for the following emission units:

(a) Coal handling operations, identified as Block 1000, consisting of:

(1) One (1) shelter-type railcar dump unloading facility, identified as EU-1000, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1000, exhausting to stack EU-1000, consisting of:

(A) Two (2) enclosed receiving pits, identified as Receiving Pit 1 and Receiving Pit 2, discharging to Receiving Bin 1 and Receiving Bin 2, respectively.
(B) Two (2) enclosed receiving bins, identified as Receiving Bin 1 and Receiving Bin 2, discharging to Drag Flight Feeder 1 and Drag Flight Feeder 2, respectively, with water spray dust suppression systems.
(C) Two (2) enclosed drag flight feeders, identified as Drag Flight Feeder 1 and Drag Flight Feeder 2, discharging to the Unloading Conveyor, with water spray dust suppression systems.

Under the NSPS, 40 CFR 60, Subpart Y, EU-1000 is an affected facility.

(2) One (1) enclosed rail unloading conveyor discharging to Transfer Station 1, identified as Unloading Conveyor, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

Under the NSPS, 40 CFR 60, Subpart Y, the Unloading Conveyor is an affected facility.

(3) One (1) enclosed transfer station discharging to Conveyor 1, Conveyor 2, or Conveyor 9, identified as Transfer Station 1 (EU-1001), approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

Under the NSPS, 40 CFR 60, Subpart Y, Transfer Station 1 (EU-1001) is an affected facility.

(4) One (1) enclosed feed conveyor discharging to Stacker 1 Boom Conveyor/Chute, identified as Conveyor 1, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 1 is an affected facility.

(5) One (1) enclosed stacker boom conveyor/chute discharging to Coal Stockpiles #1A & #1B, identified as Stacker 1 Boom Conveyor/Chute, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Stacker 1 Conveyor/Chute is an affected facility.

(6) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #1A and Stockpile #1B, with a maximum capacity of 93,000 tons, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Stockpiles #1A and #1B are affected facilities.

(7) One (1) enclosed feed conveyor discharging to Stacker 2 Boom Conveyor/Chute, identified as Conveyor 2, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 2 is an affected facility.

(8) One (1) enclosed stacker boom conveyor/chute discharging to Coal Stockpiles #2A & #2B, identified as Stacker 2 Boom Conveyor/Chute, approved in 2018 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Stacker 2 Boom Conveyor/Chute is an affected facility.

(9) Two (2) radial conical ring coal storage piles, approved in 2018 for construction, identified as Stockpile #2A and Stockpile #2B, with a maximum capacity of 93,000 tons, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Stockpiles #2A and #2B are affected facilities.

(10) One (1) reclaimer for Stockpiles #1A & #1B, discharging to Reclaim Conveyor 6, identified as Reclaimer 1, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Reclaimer 1 is an affected facility.

(11) One (1) enclosed reclaimer conveyor, identified as Conveyor 6 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 6 is an affected facility.

(12) One (1) reclaimer for Stockpiles #2A & #2B, discharging to Reclaim Conveyor 7, identified as Reclaimer 2, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Reclaimer 2 is an affected facility.

(13) One (1) enclosed reclaimer conveyor, identified as Conveyor 7 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 7 is an affected facility.

(14) One (1) enclosed transfer station conveyor, identified as Conveyor 9 discharging to the Reclaim Transfer Station, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 9 is an affected facility.

(15) One (1) enclosed reclaim transfer station discharging to Reclaim Conveyor 8, identified as Reclaim Transfer Station (EU-1006), approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Reclaim Transfer Station is an affected facility.

(16) One (1) enclosed conveyor, identified as Reclaim Conveyor 8 discharging to the Coal Mill and Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour, with particulate emissions controlled the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 8 is an affected facility.

(b) Coal drying loop, collectively identified as EU-1008, with emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008, consisting of the following:

(1) One (1) enclosed coal mill and pulverizer, identified as Coal Mill and Pulverizer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer, with particulate emissions controlled the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Mill and Pulverizer is an affected facility.

(2) One (1) enclosed coal dryer, identified as Coal Dryer, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer Baghouse, with particulate emissions controlled by the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer is an affected facility.

(3) One (1) natural gas and process fuel gas-fired heater, identified as Coal Dryer Heater EU-1007, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 55.8 MMBtu/hr (HHV), with emissions exhausting to Stack EU-1007.

Under the NSPS, 40 CFR 60, Subpart Ja, the Coal Dryer Heater (EU-1007) is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Heater (EU-1007) is part of an affected thermal dryer.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, the Coal Dryer Heater (EU-1007) is an affected source.

(4) One (1) process baghouse, identified as Coal Dryer Baghouse, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging fines to the Block 2000 Coal Hopper, exhausting particulate and filtered nitrogen to the condenser.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Baghouse is an affected facility.

(5) One (1) water-cooled condenser, identified as Drying Loop Condenser, approved in 2018 for construction, with a nominal capacity of 40 MMBtu/hr, with particulate emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008.

Under the NSPS, 40 CFR 60, Subpart Y, the Drying Loop Condenser is part of an affected thermal dryer.

(c) Additives handling operations, identified as Block 1500, consisting of:

(1) Three (3) pneumatic (nitrogen) truck unloading systems discharging to storage silos, approved in 2018 for construction, as follows:

(A) Coarse Additive Unloading, with a maximum capacity of 20.00 tons per hour.
(B) Fine Additive Unloading, with a maximum capacity of 20.00 tons per hour.
(C) Sodium Sulfide (Na_2S) Unloading, with a maximum capacity of 10.00 tons per hour.

(2) Three (3) nitrogen-blanketed storage silos, as follows:

(A) One (1) coarse additive silo, identified as T34, approved in 2018 for construction, controlled by baghouse EU-1501, exhausting to stack EU-1501.
(B) One (1) fine additive silo, identified as T33, approved in 2018 for construction, controlled by baghouse EU-1502, exhausting to stack EU-1502.
(C) One (1) Na_2S silo, identified as T35, approved in 2018 for construction, controlled by baghouse EU-1503, exhausting to stack EU-1503.

(3) One (1) nitrogen-blanketed fine additive production system, identified as Fine Additive Production System, approved in 2018 for construction, with a maximum capacity of 3.28 tons per hour, controlled by baghouse EU-1504, exhausting to stack EU-1504, consisting of:

(A) One (1) coarse additive silo rotary feeder solid weigh scale.
(B) One (1) coarse additive screw conveyor discharging to the Fine Additive Production System.
(C) One (1) additive size reduction system, identified as Fine Additive Production System discharging to the T33 or the Block 2000 coarse additive transfer system.

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(1) One (1) enclosed hopper receiving coal from Block 1000 Coal Dryer Baghouse and discharging to the Feed Prep Screw Conveyor, identified as Coal Hopper, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Hopper is an affected facility.

(2) One (1) enclosed screw conveyor, identified as Closed Screw Conveyor, approved in 2018 for construction, with a maximum capacity of 500 tons of coal per hour and a

bottlenecked capacity of 2,263,248 tons per year, discharging to the Feed Premix Drum, identified as Closed Screw Conveyor, with particulate emissions controlled by the Coal Handling System Filter, exhausting to stack EU-2005.

Under the NSPS, 40 CFR 60, Subpart Y, the Closed Screw Conveyor is an affected facility.

(3) One (1) nitrogen-blanketed coarse additive transfer system, identified as Coarse Additive Screw Conveyor, approved in 2018 for construction, with a maximum capacity of 2.20 tons per hour, receiving material from the Block 1500 coarse additive silo and discharging to the Feed Premix Drum, with particulate emissions controlled by the Coarse Additive System Filter, exhausting to stack EU-2006.

(4) One (1) nitrogen-blanketed fine additive transfer system, identified as Fine Additive Handling System, approved in 2018 for construction, with a maximum capacity of 3.28 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Fine Additive System Filter, exhausting to stack EU-2007, consisting of:

(A) One (1) fine additive silo rotary feeder solid weigh scale.
(B) One (1) fine additive screw conveyor discharging to the Block 2000 feed premix drum.

(5) One (1) nitrogen-blanketed Na_2S slurry preparation system, identified as Na_2S Slurry Preparation, approved in 2018 for construction, with a maximum capacity of 0.077 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Na_2S Handling System Filter, exhausting to stack EU-2008, consisting of:

(A) One (1) Na_2S silo rotary feeder solid weigh scale.
(B) One (1) Na_2S screw conveyor discharging to the Na_2S mixing drum.
(C) One (1) nitrogen-blanketed mixing drum for Na_2S and Block 2000 vacuum tower VGO (vacuum gas oil) discharging to the feed premix drum.

Under the NSPS, 40 CFR 60, Subpart GGGa, the mixing drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the mixing drum is an affected source.

(6) One (1) feed premix drum, identified as Feed Premix Drum, approved in 2018 for construction, receiving coal, solid additives, and recycled vacuum gas oil (VGO) and discharging to the feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed premix drum is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed premix drum is an affected source.

(7) One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2018 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

Under the NSPS, 40 CFR 60, Subpart Ja, the feed heater EU-2001 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the feed heater EU-2001 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed heater EU-2001 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, feed heater EU-2001 is an affected source.

(8) One (1) natural gas and process fuel gas-fired indirect treat gas heater, identified as EU-2002, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 52.8 MMBtu/hr (HHV), receiving hydrogen from Block 7000 and discharging to the 1st stage reactors, exhausting to stack EU-2002.

Under the NSPS, 40 CFR 60, Subpart Ja, the treat gas heater EU-2002 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, treat gas heater EU-2002 is an affected source.

(9) One (1) first stage reactor - liquid phase hydrocracking system, identified as LPH, approved in 2018 for construction, discharging to the hot separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the first stage reactor - liquid phase hydrocracking system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the first stage reactor - liquid phase hydrocracking system is an affected source.

(10) One (1) hot separator, identified as Hot Separator, approved in 2018 for construction, discharging vapor to the 2nd stage reactors and liquids to the vacuum column feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the hot separator is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the hot separator is an affected source.

(11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the vacuum distillation tower, exhausting to stack EU-2003.

Under the NSPS, 40 CFR 60, Subpart Ja, the vacuum column feed heater EU-2003 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum column feed heater EU-2003 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum column feed heater EU-2003 is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, vacuum column feed heater EU-2003 is an affected source.

(12) One (1) vacuum distillation tower, identified as Vacuum Distillation Column, approved in 2018 for construction, discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 4000, phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the vacuum distillation tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the vacuum distillation tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum distillation tower is an affected source.

(13) One (1) second stage reactor - gas phase hydrotreating system, identified as GPH, approved in 2018 for construction, discharging to the cold separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the second stage reactor - gas phase hydrotreating system is an affected source.

(14) One (1) cold separator, identified as Cold Separator, approved in 2018 for construction, discharging non-phenolic sour water to Block 3000 and hydrocarbons to the fractionator heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the cold separator is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the cold separator is an affected source.

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2018 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

Under the NSPS, 40 CFR 60, Subpart Db, fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, the fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator heater is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator heater is an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, fractionator heater EU-2004 is an affected source.

(16) One (1) fractionator tower, identified as Fractionator Tower, approved in 2018 for construction, discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix Drum, and non-phenolic sour water to Block 3000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the fractionator tower is an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the fractionator tower is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator tower is an affected source.

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

(A) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber, approved in 2018 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine recovery unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the HP Absorber and LP Absorber are affected sources.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the HP Absorber and LP Absorber is an affected source.

(e) Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

(A) One (1) heat exchanger, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2018 for construction, where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) stripper column , identified as Stripper, approved in 2018 for construction, discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger and the reboiler and vapor to the overheads condenser, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(C) One (1) water-cooled condenser, identified as Overheads Condenser, approved in 2018 for construction, discharging condensate to the stripper condenser accumulator, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(D) One (1) accumulator drum, identified as Stripper Condenser Accumulator, approved in 2018 for construction, discharging condensate to stripper reflux and the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(E) One (1) steam-heated reboiler, identified as Stripper Reboiler, approved in 2018 for construction, discharging lean amine to the stripper reflux, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Amine Recovery Unit is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Amine Recovery Unit part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Amine Recovery Unit is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Amine Recovery Unit is an affected source.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2018 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Sour Water Stripping System is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Sour Water Stripping System is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each bypass line serving the Sour Water Stripping System is an affected source.

(3) Sulfur Recovery System, consisting of:

- (A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2018 for construction, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.
  - (i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
  - (ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.
  - (iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
  - (iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the TGTU A Heat Exchanger and molten sulfur to the sulfur product pit.
  - (v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
  - (vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
  - (vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.
  - (viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
  - (ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
  - (x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
  - (xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605A Incinerator and A-605A Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit A is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit A is an affected source.

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2018 for construction, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine recovery unit.
(x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.
(xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605B Incinerator and A-605B Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit B is an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit B is an affected source.

(f) Offsites operations, identified as Block 4000, consisting of:

(1) Flares, as follows:

(A) One (1) natural gas and process fuel gas-fired flare identified as High Pressure (HP) Flare, approved in 2018 for construction, servicing overpressure and emergency reliefs from Block 2000 VEBA Combi Cracker operations, controlling emissions from Block 2000 depressurization system, with pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(B) One (1) natural gas and process fuel gas-fired flare, identified as Low Pressure (LP) Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 7000 Hydrogen Unit operations, controlling emissions Block 7000 start-up and shut-down vents, and a continuous sweep stream from the Block 2000 slop tank, with a sweep and pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(C) One (1) natural gas and process fuel gas-fired flare, identified as Sulfur Block Flare, approved in 2018 for construction, servicing overpressure reliefs from Block 3000 Sulfur Recovery operations and sulfur loading, controlling emergency streams from Sulfur Recovery Units A and B, and a continuous sweep stream from the sour water storage tanks, with a sweep and pilot heat input capacity of 0.77 MMBtu/hr (LHV), exhausting to the atmosphere.

(D) One (1) natural gas and process fuel gas-fired flare, identified as Loading Flare, approved in 2018 for construction, servicing Block 4000 naphtha, diesel, and ammonia loading operations, with a pilot heat input capacity of 0.20 MMBtu/hr (LHV), exhausting to the atmosphere.

Under the NSPS, 40 CFR 60, Subpart Ja, the flares are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, the flares are affected facilities.

Under the NESHAP, 40 CFR 63, Subpart CC, the flares are affected sources.

(2) Product storage tanks, approved in 2018 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T1	IFR	Naphtha product	4,629,879 (17,524)	-
T2	IFR	Naphtha product	4,629,879 (17,524)	-
T3	FR	Diesel product	4,525,796 (17,130)	-
T4	FR	Diesel product	4,525,796 (17,130)	-
T5	FR	Diesel product	4,525,796 (17,130)	-
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)	-
T7	FR	Molten sulfur	342,367 (1,296)	-
T8	FR	Molten sulfur	342,367 (1,296)	-
T9	HPV	Ammonia product	36,720 (17,524)	-
T10	FR	Residue surge tank 1	926,980 (17,524)	-
T11	FR	Residue surge tank 2	926,980 (3,509)	-
T12	FR	Residue feed tank	926,980 (3,509)	-
T13	FR	VGO tank 1	926,980 (3,509)	-
T14	FR	VGO tank 2	926,980 (3,509)	-
T15	HPV	LPG storage	48,872 (185)	-
T16	FR	Slop tank	4,195,581 (15,880)	LP flare
T17	FR	Diesel fuel tank	23,775 (90)	-
T18	FR	Non-phenolic sour water storage tank 1	1,268,026 (4,799)	SB flare
T19	FR	Non-phenolic sour water storage tank 2	1,268,026 (4,799)	SB flare
T20	FR	Non-phenolic sour water storage tank 3	1,268,026 (4,799)	SB flare
T21	FR	Phenolic sour water storage tank	40,947 (155)	SB flare
T22	FR	Stripped non-phenolic sour water surge tank	1,268,026 (4,799)	-
T23	FR	Stripped phenolic sour water surge tank	13,737 (52)	-
T24	FR	Amine surge/deinventory tank	63,943 (242)	-
T25	FR	Fresh amine tank	63,943 (242)	-

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T26	FR	Amine containment tank (sump)	793 (3)	-

1. FR - fixed roof, IFR - internal floating roof, HPV-horizontal pressure vessel
2. Tank vents to flares are part of sweep and pilot gas streams.

Under the NSPS, 40 CFR 60, Subpart Kb, T1, T2, and T6 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, T1 - T6 and T10 - T15 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart QQQ, T16 is part of an affected facility.

Under the NSPS, 40 CFR 61, Subpart FF, T16 and T18 - T21 are part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, T1 - T6, T10 - T14, T16, and T18-T23 are part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart WW, T3 - T6 and T10 - T14 are affected sources.

(3) Loading operations, as follows:

(A) One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2018 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the Product Loading Rack is an affected facility.

Under the NESHAP, 40 CFR 61, Subpart BB, the Product Loading Rack is an affected source.

Under the NESHAP, 40 CFR 63, Subpart CC, the Product Loading Rack is an affected source.

(B) One (1) single-spot railcar loading rack for ammonia, identified as Ammonia Loading Rack, approved in 2018 for construction, with a bottlenecked capacity of 15,024,167 gallons per year, controlled by the Loading Flare.

(C) One (1) single-spot railcar loading rack for molten sulfur, identified as Sulfur Loading Rack, approved in 2018 for construction, with a bottlenecked capacity of 63,781 tons per year, controlled by the Sulfur Block Flare.

(g) Residue solidification operations, identified as Block 5000, as follows:

(1) Four (4) pastillators, identified as EU-5001A - EU5001D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5001.

(2) Four (4) pastillators, identified as EU-5002A - EU5002D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5002.

(3) Four (4) pastillators, identified as EU-5003A - EU5003D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5003.

(4) Four (4) pastillators, identified as EU-5004A - EU5004D, approved in 2018 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5004.

(5) Enclosed conveyors for residue pellets, with particulate emissions controlled by filters EU-5009, EU-5010, and EU-5011, as follows:

(A) One (1) enclosed conveyor, identified as Block 1 & 2 transfer conveyors, with a maximum capacity of 34.33 tons per hour, receiving pastillators from the eight (8) pastillators, identified as EU-5001A - EU5001D and EU-5002A - EU5002D.

(B) One (1) enclosed conveyor, identified as Block 3 & 4 transfer conveyors, with a maximum capacity of 34.33 tons per hour, receiving pastillators from the eight (8) pastillators, identified as EU-5003A - EU5003D and EU-5004A - EU5004D.

(C) One (1) enclosed loading conveyor, identified as Loading Conveyor, approved in 2018 for construction, with a maximum capacity of 51.49 tons per hour, receiving pastillators from Block 1 & 2 and Block 3 & 4 transfer conveyors, and discharging to the bulk container loading station, railcar residue silo, or swing residue silo.

(6) One (1) residue bulk container loading station, identified as EU-5009, approved in 2018 for construction, with a maximum capacity of 8.00 tons per hour, using filter EU-5009 for particulate control and exhausting to stack EU-5009.

(7) One (1) railcar residue storage silo, identified as EU-5010, approved in 2018 for construction, with a maximum capacity of 1,236 tons per day, using baghouse EU-5010 for particulate control and exhausting to stack EU-5010.

(8) Two (2) residue loading hoppers, identified as EU-5005 and EU-5006, approved in 2018 for construction, with a combined maximum capacity of 1,236 tons per day, receiving residue from the railcar residue storage silo, using baghouse EU-5010 for particulate control and exhausting to stack EU-5010.

(9) One (1) swing residue storage silo, identified as EU-5011, approved in 2018 for construction, with a maximum capacity of 1,236 tons per day, using baghouse EU-5011 for particulate control and exhausting to stack EU-5011.

(10) Two (2) residue loading hoppers, identified as EU-5007 and EU-5008, approved in 2018 for construction, with a combined maximum capacity of 1,236 tons per day, receiving residue from the swing residue storage silo, using baghouse EU-5011 for particulate control and exhausting to stack EU-5011.

(11) Residue loadout operations using spouts and choke flow-practices, as follows:

(A) Two (2) railcar loadspots, approved in 2018 for construction.

(B) Two (2) swing loadspots, approved in 2018 for construction, accommodating either trucks or railcars.

(h) Utilities operations, identified as Block 6000, consisting of:

(1) One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2018 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 68.50 MMBtu/hr (HHV), exhausting to stack EU-6000.

Under the NSPS, 40 CFR 60, Subpart Dc, boiler EU-6000 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, boiler EU-6000 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, boiler EU-6000 is an affected source.

(2) One (1) three-cell crossflow mechanical draft cooling tower, identified as EU-6001, approved in 2018 for construction, with a maximum capacity of 32,000 gallons per hour, equipped with mist eliminators and exhausting to stacks EU-6001, EU-6002, and EU-6003.

(3) One (1) diesel engine-driven emergency generator, identified as EU-6006, approved in 2018 for construction, with a maximum heat input capacity of 19.60 MMBtu/hr (2,800 hp) (average heating value), exhausting to stack EU-6006.

Under the NSPS, 40 CFR 60, Subpart IIII, emergency generator EU-6006 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart ZZZZ, emergency generator EU-6006 is an affected source.

(4) One (1) diesel engine-driven emergency fire pump, identified as EU-6008, approved in 2018 for construction, with a maximum heat input capacity of 5.25 MMBtu/hr (750 hp) (average heating value), exhausting to stack EU-6008.

Under the NSPS, 40 CFR 60, Subpart IIII, emergency fire pump EU-6008 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart ZZZZ, emergency fire pump EU-6008 is an affected source.

(i) Water supply and treatment operations, identified as Block 6500, consisting of:

(1) One (1) pneumatic lime truck unloading system, identified as Lime Unloading, approved in 2018 for construction, with a maximum capacity of 20.00 tons per hour, discharging to silo EU-6501.

(2) One (1) lime storage silo, identified as EU-6501, approved in 2018 for construction, with a maximum capacity of 20.00 tons per hour, with particulate emissions controlled by dust collector EU-6501 and exhausting to stack EU-6501.

(j) Hydrogen unit operations, identified as Block 7000, as follows:

(1) Hydrogen Plant 1, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7003, identified as Feed Water Treatment System 1, approved in 2018 for construction, exhausting to stack EU-7003.

(B) One (1) feed preparation train, identified as Feed Prep 1, approved in 2018 for construction, consisting of:

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7001, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7001, is an affected facility.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 1, approved in 2018 for construction, discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 1, approved in 2018 for construction, discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 1 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 1 is an affected source.

(2) Hydrogen Plant 2, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7004, identified as Feed Water Treatment System 2, approved in 2018 for construction, exhausting to stack EU-7004.

(B) One (1) feed preparation train, identified as Feed Prep 2, approved in 2018 for construction, consisting of:

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7002, approved in 2018 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7002, is an affected facility.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2018 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 2, approved in 2018 for construction, discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 2, approved in 2018 for construction, discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, Hydrogen Plant 2 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 2 is an affected source.

(k) Wastewater treatment operations, identified as Block 8000, as follows:

(1) One (1) wastewater junction box with associated process drains, identified as Oily Water Sump, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8002.

(2) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Water Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and water to MH1.

(3) One (1) wastewater junction box with, identified as MH1, approved in 2018 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8003.

(4) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Amine Separator, approved in 2018 for construction, discharging oil to the Slop Tank (T16) and amine solution to the Rich Amine Return Header.

(5) One (1) biological wastewater treatment system, approved in 2018 for construction, with emissions exhausting to vent EU-8001.

Under the NSPS, 40 CFR 60, Subpart QQQ, the process drains, junction boxes, Oily Water Separator, Oily Amine Separator, associated sewer lines, and any secondary oil-water separator in the biological wastewater treatment system are an affected aggregate facility.

Under the NESHAP, 40 CFR 61, Subpart FF, the Oily Water Separator, Oily Amine Separator, and any secondary oil-water separator in the biological wastewater treatment system are affected sources.

Under the NESHAP, 40 CFR 63, Subpart CC, the wastewater streams and treatment operations associated with petroleum refining process units are part of a new affected source..

Summary of the Best Available Control Technology (BACT) Process

IDEM, OAQ conducts BACT analyses in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, which outlines the steps for conducting a top-down BACT analysis. Those steps are listed below:

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls and document the results; and
(5) Select BACT.

Also in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, BACT analyses take into account the energy, environmental, and economic impacts of the control options. Emission reductions may be determined through the application of available control techniques, process design, and/or operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause adverse environmental effects to public health and the environment.
The Office of Air Quality (OAQ) makes BACT determinations by following the five steps identified above.

This BACT determination is based on the following information:

(1) The EPA RACT/BACT/LAER (RBLC) Clearinghouse;
(2) EPA and State air quality permits;
(3) Communications with control device equipment manufacturers;
(4) Technical books and articles; and
(5) Guidance documents from state and federal agencies.

Particulate (PM, PM_{10} and $PM_{2.5}$) BACT Analysis
Material Handling

Step 1: Identify Potential Control Technologies

Particulate matter (PM) is a complex mixture of small particles and liquid droplets. PM can be made up of a variety of components, including acids, organic chemicals, metals, and soil or dust particles. PM includes any size of filterable particulate. Filterable particulate is the particulate that is emitted directly as a solid or liquid at the stack.

Emissions of particulate matter (PM) are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, PM emissions are controlled through one of the following mechanisms:

(1) Mechanical collectors (such as cyclones or multiclones).
(2) Wet scrubbers.
(3) Electrostatic precipitators (ESP).
(4) Fabric filter dust collectors (baghouses).
(5) Wet suppression

Fugitive PM emissions from paved roads are typically controlled through the use of work practices which include a site-specific Fugitive Dust Control Plan.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Mechanical Collectors (such as Cyclones or Multiclones)

Mechanical collectors use the inertia of the particles for collection. The particulate-laden gas stream enters the control device and is forced to move in a cyclonic manner, which causes the particles to move toward the outside of the vortex. Most of the large-diameter particles enter a hopper below the cyclonic tubes while the gas stream turns and exits the device.

Cyclones are typically used to remove relatively large particles from gas streams. Conventional single cyclones are estimated to control PM at 70-90%, PM_{10} at 30-90%, and $PM_{2.5}$ at 0-40%. High efficiency single cyclones are designed to achieve higher control of smaller particles and multiclones may also achieve higher control of smaller particles. Collection efficiency generally increases with particle size and/or density, inlet duct velocity, cyclone body length, number of gas revolutions in the cyclone, ratio of cyclone body diameter to gas exit diameter, dust loading, and smoothness of the cyclone inner wall. Cyclone efficiency will decrease with increases in gas viscosity, body diameter, gas exit diameter, gas inlet duct area, and gas density.

Cyclones are often used for recovery and recycling of material or as precleaners for more expensive final control devices such as fabric filters or electrostatic precipitators. Cyclones are used for applications such as after spray drying operations in the food and chemical industries; after crushing/grinding/calcining operations in the mineral and chemical industries to collect salable or useful material; for first stage control of PM from sinter plants, roasters, kilns, and furnaces in the metallurgical industries; for catalyst recycling in the fluid-cracking process; and for precleaning fossil-fuel and wood-waste fired industrial and commercial fuel combustion units.

The typical gas flow rates for a single cyclone are 1,060 to 25,400 scfm. Flows that are higher use multiple cyclones in parallel. Inlet gas temperatures are only limited by the material of construction of the cyclone. Cyclones perform more efficiently with higher pollutant loadings, with loadings typically ranging from 1.0 to 100 gr/scf. Cyclones are unable to handle sticky or tacky materials.

Wet Scrubbers

A wet scrubber is an air pollution control device that removes PM from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove PM, including venturi, impingement and sieve plate, spray towers, mechanically aided, condensation growth, packed beds, ejector, mobile bed, caternary grid, froth tower, oriented fiber pad, and wetted mist eliminators. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the PM size decreases. Collection efficiencies also vary with scrubber type. Collection efficiencies range from greater than 99% for venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are smaller and more compact than baghouses or ESPs. They have lower capital costs and comparable operation and maintenance (O&M) costs. Wet scrubbers are particularly useful in the removal of PM with the following characteristics:

(1) Sticky and/or hygroscopic materials (materials that readily absorb water);
(2) Combustible, corrosive and explosive materials;
(3) Particles which are difficult to remove in their dry form;
(4) PM in the presence of soluble gases; and
(5) PM in waste gas streams with high moisture content.

Some applications of wet scrubbers include the following:

- Condensation scrubbers: for controlling fine PM-containing waste-gas streams.

- Fiber-bed scrubbers (wetted-fiber scrubbers or mist eliminators): for controlling aerosol emissions from chemical, plastics, asphalt, sulfuric acid, and surface coating industries; for controlling lubricant mist emission from rotating machinery and storage tanks; and for eliminating visible plume downstream of other control devices.

- Impingement-plate/tray-tower scrubbers: for the food and agriculture industry and at gray and iron foundries. These types of scrubbers may be used to control other pollutants such as SO_2, VOC, and HAPs in other settings.

- Mechanically-aided scrubbers: for food processing paper, pharmaceuticals, chemicals, plastics, tobacco, fiberglass, ceramics, and fertilizer. Processes controlled include dryers, cookers, crushing and grinding operations, spraying, ventilation, and material handling.

- Orifice scrubbers: for food processing and packaging; pharmaceutical processing and packaging; manufacture of chemicals, rubber and plastics, ceramics, and fertilizer. Processes controlled include dryers, cookers, crushing and grinding operations, spraying, ventilation, and material handling.

- Packed-bed/packed-tower wet scrubbers: for the chemical, aluminum, coke and ferroalloy, food and agriculture, and chromium electroplating industries.

- Spray-chamber/spray-tower wet scrubbers: often used as part of a flue gas desulfurization systems, where they are used to control emissions from coal and oil combustion from electric utilities and industrial sources.

- Venturi scrubbers: for controlling PM emissions from utility, industrial, commercial, and institutional boilers fired with coal, oil, wood, and liquid waste; for sources in the chemical, mineral products, wood, pulp and paper, rock products, and asphalt manufacturing industries; for lead, aluminum, iron and steel, and gray iron production industries; for municipal solid waste incinerators. They are typically used where it is necessary to obtain high collection efficiencies for fine PM.

The primary disadvantage of wet scrubbers is that increased collection efficiency comes at the cost of increased pressure drop across the control system. Another disadvantage is that they generate waste in the form of a sludge which requires treatment and/or disposal. Lastly, downstream plume visibility problems can result unless the added moisture is removed from the gas stream.

Electrostatic Precipitators

An electrostatic precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The particles are given an electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane.

Once the particles are collected on the plates, they must be removed from the plates without re-entraining them into the gas stream. This is usually accomplished by knocking them loose from the plates, allowing the collected layer of particles to slide down into a hopper from which they are evacuated. Some precipitators remove the particles by intermittent or continuous washing with water.

Dry-type ESPs are primarily used in the electric utility industry and may also be used by the textile industry, pulp and paper facilities, the metallurgical industry, cement and mineral industry, sulfuric acid manufacturing plants, as well as for coke ovens and hazardous waste incinerators. Dust characteristics are a limiting factor for dry-type ESPs. Sticky, moist, high resistivity, flammable, or explosive dusts and particles are not well-suited for dry-type ESPs. Wet ESPs are used in situations for which dry ESPs are not suited, such as when the material to be collected is wet, sticky, flammable, explosive, or has a high resistivity. Wet ESPs are commonly used by the textile industry, pulp and paper facilities, the metallurgical industry, and sulfuric acid manufacturing plants. The limiting factor for wet ESPs is temperature; typically wet ESPs cannot handle operating temperatures exceeding 170°F.

ESP control efficiencies are very high and can range from 95% to 99.9% due to the strong electrical forces applied to small particles and can handle high temperatures (dry ESPs), pressures, and gas flow rates. The composition of the particulate matter is very important because it influences the conductivity within the dust layers on the collection plate. Wet ESPs are effective at collecting sticky particles and mist, help to cool and condition gas streams, and may provide for control of other aerosolized pollutants in the gas stream. ESPs in general are not suited for use in processes which are highly variable because they are very sensitive to fluctuations in gas stream conditions (flow rates, temperatures, particulate and gas composition, and particulate loadings). They have high capital costs and require large installation space. Dry ESPs are not recommended for removing sticky or moist particles. Wet ESPs can have potential problems with corrosion and they generate a wastewater slurry that must be handled.

Fabric Filtration

A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal.

Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9%. The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake. Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting.

Fabric filters are used where high efficiency particle collection is required and can be used in most any process where dust is generated and can be collected and ducted to a central location. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation and that cannot be economically accommodated. Important process variables include particle characteristics, gas characteristics, and fabric properties. The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

Fabric filters provide high collection efficiency for both coarse and fine particles and are relatively insensitive to fluctuations in gas stream conditions. Operation is simple and fabric filters are useful for collecting particles with resistivities either too low or too high for collection with ESPs. Fabric filters have limited application for high temperatures and corrosive or moist exhaust.

Wet Suppression

Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles. There are two types of wet suppression systems: liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems which supply foams as the wetting agent. Wet suppression systems typically achieve PM control efficiencies of greater than 85%.

Step 2: Eliminate Technically Infeasible Options:

For material handling, all of the control technologies are considered technically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Control Option	**Expected Control Efficiency**
Fabric filter dust collectors (baghouses)	99+%
Electrostatic precipitators (ESP)	95-99%
Mechanical collectors (such as cyclones or multiclones)	70% - 90%
Wet scrubbers	70% - 90%
Wet suppression	50% - 90%

Step 4: Evaluate the Most Effective Controls and Document the Results

The following tables summarize other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Rail Unloading - coal

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (Emission unit)	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*railcar dump unloading facility, consisting of: Receiving Pits 1 & 2 Receiving Bins 1 & 2 Drag Flight Feeders 1& 2 (EU-1000)*	*Shelter-type enclosure and baghouse EU-1000 Water spray dust suppression (hoppers and feeder only)*	*PM/PM10/PM2.5: 0.0022 gr/dscf 0.12 lb/hr 5% opacity (6-min avg.)*	5,000 ton/hr
New Steel International	OH-0315 07-00587 (5/6/2008)	Scrap barge unloading to truck and Coal and Iron Ore barge unloading	baghouses 1A and 1B	PM/PM10: 0.0022 gr/dscf, 0.93 lb/hr and 4.07 tpy Fugitive PM: 6.15 tpy and fugitive PM10: 2.84 tpy	
0.0022 gr/dscf is the most stringent grain loading. Therefore, this has been determined to be BACT.					
Southeast Idaho Energy, LLC	ID-0017 P-2008.0066 (2/10/2009)	railcar unloading & storage	baghouses	PM: 0.0009 gr/dscf 0.09 lb/hr 99% CE 5% opacity	5,000 tons/hr
				PM10: 0.0004 gr/dscf 0.04 lb/hr 99% control efficiency	
5% opacity is most stringent limit. Therefore this has been determined to be BACT.					
Permit cited in ID-0017, and later revision P-2009.0127, do not incorporate gr/dscf limits, only lb/hr and opacity. Value of gr/dscf calculated from lb/hr limit and air flow rate provided in the permit conflicts with the gr/dscf value in RBLC. Therefore the gr/dscf value from OH-0315 is considered in determining BACT.					
Indiana Gasification - IN	IN-0166 T147-30464-00060 (6/27/2012)	Rail Unloading	Baghouse or dust extraction system	PM/PM10: 0.003 gr/dscf PM2.5: 0.0015 gr/dscf 99.0% CE	-

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (Emission unit)	Control	BACT	Throughput (ton/yr)
This includes the most stringent limit (PM2.5), however, this plant was not built and the permit was revoked. Therefore these emission limits cannot be verified and are not considered as BACT.					
East Kentucky Power Cooperative, Inc - J.K. Smith Generating Station	KY-0100 V-05-070 R3 (4/09/2010)	storage piles, railcar unloading, egress to underground conveyor	wet suppression	10% opacity	3000 tph
Ohio River Clean Fuels	OH-0317 02-22896 (11/20/2008)	coal handling and storage	-	PM: 0.09 lb/hr PM10: 0.04 lb/hr	-
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Homeland Energy Solutions	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Coal Unloading/storage	Baghouse and water fogging	PM/PM10: 0.005 gr/dscf	200 tons/hr
Tri-State Generation and Transmission Assoc	CO-0072 12MF322-1 (5/16/2007)	coal handling and storage (train unloading, crushers, transfer, silo and storage piles)	water spray bars	PM: 1.7 tpy PM10: 0.7 tpy	4500000 ton/yr
NRG Coal Handling Plant	TX-0507 8579, PSD-TX-371M4 (4/13/2006)	Rail Unloading	None	PM: 1.15 lb/hr PM10: 0.54 lb/hr	-
Public Service Company Of Colorado Comanche Station	CO-0057 04UNITPB1015 (07/05/2005)	coal handling and storage (includes open storage pile, rail unloading, transfer to pile and transfer to bunkers)	Water Sprays, lower well, dust suppressant, Enclosures and baghouses where feasible	PM/PM10: 0.01 gr/dscf	-
Mesabi Nugget	MN-0061 13700318-001 (6/26/2005)	coal unloading	baghouse	0.005 gr/dscf 10% opacity	
Auburn Nugget	IN-0119 033-19475-00092 (5/31/2005)	coal car unloading	Baghouse	PM: 0.0052 gr/dscf 3% opacity	165 tph

Conveyor transfer - coal

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Unloading Conveyor, Transfer Station (EU-1001)*	*baghouse*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.16 lb/hr (EU-1001)* *5% opacity (6-min avg.)*	5,000 tons/hr
		Closed Screw Conveyor	*coal handling system filter (EU-2005)*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.003 lb/hr* *5% opacity (6-min avg.)*	500 tons/hr (max) 258 tons/hr (bottlenecked)
US Steel	MN-0084 13700063-004 (12/6/2011)	Reclaim conveyor	Baghouse	PM/PM10/PM2.5: 0.002 gr/dscf 0.31 lb/hr, *5% opacity (6-min avg.),* 95% CE	
0.002 gr/dscf is the most stringent limitation for conveyor transfer, therefore this has been determined to be BACT.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Great River Energy-Spiritwood	ND-0024 PTC07026 (9/14/2007)	coal handling	baghouse	PM: 0.005 gr/dscf 5% opacity 99.9% CE	85.3 tph
5% opacity is the most stringent opacity. Therefore, this has been determined to be BACT.					
Indiana Gasification - IN	IN-0166 / T147-30464-00060 (6/27/2012)	Conveyor Transfer	Baghouse	PM/PM10: 0.003 gr/dscf *PM2.5: 0.0015 gr/dscf 99.0% CE	750 tph
This plant was not built and the permit was revoked. Therefore these emission limits cannot be verified and are not considered as BACT.					
Holland Board Of Public Works-James Deyoung Plant	MI-0403 25-07 (2/11/2011)	Barge unloading system; all coal fuel conveyors and transfer points; reclaim hopper and vibrating feeders; coal drop points; transfer / crusher house; active storage pile; and inactive storage pile	Fabric filter controls emissions from the transfer/crusher house. conveyors are equipped with three sided enclosures	PM: 0.004 gr/dscf PM10: 0.34 lb/hr 10% opacity	-
Duke Energy-Edwardsport	IN-0139 083-28683-00003 (3/1/2010)	Coal handling and transfer	Baghouse/bin vent collector insertable dust collector	PM: 0.003 gr/dscf 99.0% CE	12000 tph
Sun Coke Energy	OH-0332 P0104768 (2/9/2010)	coal handling, processing and transfer	Enclosure and wet suppression	PM: 4.6 lb/hr (3.47 tpy) PM10: 4.6 lb/hr (1.67 tpy) PM2.5: 4.6 lb/hr (0.52 tpy) VE: 10% Opacity	3750 ton/d
American Municipal Power	OH-0310 P0104461 (10/8/2009)	coal conveying, handling, and crushing	baghouse with option of enclosures, fogging, wet suppression	PM: 77.6 lb/hr (9.8 tpy) PM10: 9.0 tpy	5,553,840 tpy
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	coal and biomass converyors/ transfer towers Totally enclosed towers and transfer points	Baghouse and dust collector	PM10: 0.9 lb/hr (3.9 tpy) 0.005 gr/dscf 99.9% CE 20.0% Opacity NSPS Y	3500 tph
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Martin Marietta	OH-0321 03-17089 (11/13/2008)	coal and coke material handling	building enclosure and high moisture content coal and coke >5%	PM: 3.15 tpy PM10: 0.95 tpy 20% opacity	78,840 tpy
Louisiana Generating, LLC Big Cajun	LA-0223 PSD-LA-660(M-1) (1/8/2008)	conveyors	Wind screens and dry fogging	PM10: 0.06 lb/hr 0.03 tpy	1200 tph
Basin Electric Power Coop.	WY-0064 CT-4631 (10/15/2007)	coal handling	enclosed system with vents feeding fabric filters	PM10: 0.005 gr/dscf	-
Homeland Energy	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	coal receiving and handling	water fogging at coal handling area, baghouse to control storage bin	PM/PM10: 0.005 gr/dscf	200 tph
Cutler-Magner Co.	WI-0233 05-DCF-412 (8/16/2006)	coal storage and handling	fabric filter baghouse, total enclosure of the process operations	PM: 0.04 lb/hr (0.005 gr/dscf)	-

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Public Service Company Of Colorado Comanche Station	CO-0057 04UNITPB1015 07/05/2005)	coal handling and storage (includes open storage pile, rail unloading, transfer to pile and transfer to bunkers)	Water Sprays, lower well, dust suppressant, Enclosures and baghouses where feasible	PM/PM10: 0.01 gr/dscf	-
Montana Dakota Utilities	ND-0021 PTC 05005 (6/3/2005)	coal handling	baghouses	PM: 0.005 gr/dscf	400 tph
Newmont Nevada Energy Investment	NV-0036 AP4911-1349 (5/5/2005)	coal handling	baghouse	PM/PM10: 0.01 gr/dscf	-

Coal Stockpiles

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Conveyor 1, Conveyor 2* *Stacker 1 Boom/Chute, Stacker 2 Boom/Chute* *Coal storage piles (Stockpiles #1A & #1B, #2A & #2B)* *Reclaimer 1, Reclaimer 2* *Conveyor 6, Conveyor 7, Conveyor 9, and Reclaim Transfer Station (EU-1006)*	*negative pressure enclosure and baghouse EU-1006*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.11 lb/hr* *5% opacity*	5,000 tons/hr
Southeast Idaho Energy LLC	ID-0017 P-2008.0066 (2/10/2009)	coal/petcoke railcar unloading & storage, SRC01-SRC07	Enclosed railcar unloading at negative pressure. Covered conveyors and enclosed transfer points. Storage in Eurosilo or equivalent. High efficiency baghouses (railcar unloading, conveyors, storage silo vents).	PM: 0.0009 gr/dscf 99% control efficiency 0.09 lb/hr 5% opacity PM10: 0.0004 gr/dscf 99% control efficiency 0.04 lb/hr	5,000 tons/hr
Permit cited in ID-0017, and later revision P-2009.0127, do not incorporate gr/dscf limits, only lb/hr and opacity. Value of gr/dscf calculated from lb/hr limit and air flow rate provided in the permit conflicts with the gr/dscf value in RBLC. Therefore the concentration equivalent to the entry below, also equivalent to the value from the conveyor transfer table above, is determined to be BACT.					
US Steel Corp - Keetac: Keewatin, MN	MN-0084 13700063-004 (12/6/2011)	coal bin	Baghouse (bin vent)	PM/PM10/PM2.5: 0.14 lb/hr (0.002 gr/dscf) 95.0% CE	-
Ag Processing Inc.	NE-0059 CP14-007 (3/25/2015)	grain receiving and handling (6 units routed to 1 stack. Grain Truck Dump Pit #1, Grain Elevator #1, Grain Truck Dump Pit #2, Grain Elevator #2, Conveyor #1, and Scalper)	baghouse	PM/PM10: 0.003 gr/dscf 0.82 lb.hr	20,000 bu/hr
Grain handling and storage processes may not be representative of BACT for coal.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
University of Northern Iowa	IA-0086 02-111 (5/3/2007)	Coal system - bunker #3 silo	baghouse	PM/PM10: 0.005 gr/dscf VE: 5% opacity	27.4 lb/hr
Value presented as throughput may not be accurate.					

Coal Milling/Drying

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Conveyor 8* *Coal milling/drying*	*Loop purge baghouse (EU-1008)*	*PM/PM10/PM2.5: 0.002 gr/dscf* *0.26 lb/hr* *No VE except 1 min in any 60 min*	500 tons/hr (max) 258 tons/hr (bottlenecked)
Essar Steel Minnesota	MN-0085 06100067-004 (5/10/2012)	Taconite - secondary screening crusher/cobber line	Fabric filter with leak detection	PM/PM10/PM2.5: 0.002 gr/dscf 0.39 lb/hr VE: 5% for 6-min avg.	
0.002 gr/dscf is the most stringent limit. Therefore, this has been determined to be BACT.					
American Municipal Power	OH-0310 P0104461 (10/8/2009)	coal conveying/handling/crushing	baghouse with option of enclosures, fogging, wet suppression	PM: 77.6 lb/hr and 9.8 tpy PM10: 9.0 tpy No VE except 1 min in any 60 min	
VE: 0% opacity except for 1 min in any 60 min is the most stringent VE. Therefore, this has been determined to be BACT					
Wolverine Power Supply	MI-0400 317-07 (6/29/2011)	coal crushers	baghouse	2.0e-5 gr/dscf PM10/PM2.5: 27.6e-4 lb/hr VE: 10% opacity drop and transfer points, 5% opacity dust collector 99% CE	
State tracking system does not show a Part 70 permit for a source in the county identified in the RBLC entry. The source may not have been constructed. Therefore this is not considered representative of BACT for the proposed source.					
East Kentucky Power Cooperative, Inc - J.K. Smith Generating Station	KY-0100 V-05-070 R3 (4/09/2010)	coal crushing and silo storage	baghouse	0.005 gr/dscf	
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	coal and biomass crusher houses	Baghouse and totally enclosed crusher houses	0.005 gr/dscf 99.9% CE PM10: 1.2 lb/hr & 5.3 tpy 20% opacity	-
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Louisiana Generating, LLC Big Cajun	LA-0223 PSD-LA-660(M-1) (1/8/2008)	fuel crusher house	baghouse	0.04 lb/hr and 0.06 tpy	
NRG Coal Handling Plant	TX-0507 8579, PSD-TX-371M4 (4/13/2006)	crusher house	none	PM: 0.76 lb/hr & 3.33 tpy PM10: 0.36 lb/hr & 1.58 tpy	
Cleveland Cliffs, Northshore Mining	MN-0064 07500003-003 (3/22/2006)	Taconite - tertiary crushing	baghouse	PM/PM10: 0.0025 gr/dscf	

Material Storage in Silos and Bins

The additives used at this source consist of different types of dry powdery type materials. A search in the RBLC only includes one entry for "pneumatic" and a few entries for "additive" (included in the table below).

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*EU-1501* *Coarse additive unloading*	*Baghouse EU-1501*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.016 lb/hr*	-
		EU-1502 *Fine additive unloading*	*Baghouse EU-1502*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.018 lb/hr*	
		EU-1503 *Sodium sulfide unloading*	*Baghouse EU-1503*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.013 lb/hr*	
		EU-2006 *Coarse additive conveyor*	*Filter EU-2006*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.004 lb/hr*	
		EU-2007 *Fine additive handling system*	*Filter EU-2007*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.004 lb/hr*	
		EU-2008 *Sodium sulfide handling system*	*Filter EU-2008*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.001 lb/hr*	
		Residue conveyor	*total enclosure, silo/hopper bin vent filters*	*see EU-5009, EU-5010, and EU-5011*	
		EU-5009 *Residue container loading station*	*Filter EU-5009*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.001 lb/hr*	
		EU-5010 *Residue rail storage silo, loading hoppers EU-5005 & EU-5006*	*Filter EU-5010*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.003 lb/hr*	
		EU-5011 *Residue swing storage silo, loading hoppers EU-5007 & EU-5008*	*Filter EU-5011*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.003 lb/hr*	
		EU-6501 Lime unloading	*Baghouse EU-6501*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.01 lb/hr*	
Mag Pellet, LLC (formerly Magnetation)	IN-0167 T181-32081-00054 (4/16/2013)	Pneumatic transfer for each of the following:	see below:		-
		Coke Breeze grinding (EU004b),	Baghouse	PM/PM10/PM2.5: 0.002 gr/dscf and 0.1388 lb/hr	
		WBE Lime Storage Area (EU020) Bentonite	Bin Vent	PM/PM10/PM2.5: 0.002 gr/dscf and 0.02 lb/hr	
		Unloading and Storage Area (EU005)	Bin Vent Filter	PM/PM10/PM2.5: 0.002 gr/dscf and 0.0496 lb/hr	
		Ground Limestone and Dolomite Area Additive System (EU010)	Baghouse	PM/PM10/PM2.5: 0.002 gr/dscf and 0.32 lb/hr	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
US Steel Corp - Keetac: Keewatin, MN	MN-0084 13700063-004 (12/6/2011)	This process isn't pneumatic. Therefore, it wasn't considered a similar process for this BACT review.			
		Bentonite Bin	PM: Baghouse/Bin Vent	0.002 gr/dscf and 0.021 lb/hr	
		Alternative Fuels Intermediate Dry Fuel Silo	PM: Baghouse/Bin Vent	0.002 gr/dscf and 0.11 lb/hr)	
		Alternative Fuels Prepared Dry Fuel Silo	PM: Baghouse/Bin Vent,	0.002 gr/dscf and 0.07 lb/hr	
		Final Transfer Conveyors and Loadout Conveyor	PM: Baghouse with Leak Detection,	0.002 gr/dscf and 0.21 lb/hr	
		Reclaim Conveyor	PM: Baghouse with Leak Detection	0.002 gr/dscf and 0.31 lb/hr	
		Emergency Pellet Conveyor Transfer	PM: Baghouse with Leak Detection	0.002 gr/dscf and 0.21 lb/hr	
		Coal Bin 2	PM: Baghouse/Bin Vent	0.002 gr/dscf and 0.14 lb/hr	
		Limestone Bin	PM: Baghouse/Bin Vent	0.002 gr/dscf and 0.21 lb/hr	
		Mill Feeder 1	PM: Baghouse with Leak Detection	0.002 gr/dscf and 0.51 lb/hr	
		Lime Bin	PM: Baghouse/Bin Vent	0.002 gr/dscf and 0.02 lb/hr	
0.002 gr/dscf is the most stringent grain loading. Therefore, this has been determined to be BACT.					
New Steel International: Haverhill, OH	OH-0315 07-00587 (5/6/2008)	Alloy, Flux, Carbon, Limestone, & Coke Handling	PM: Enclosures/Baghouse	1.4 lb/hr, 6.13 tons/yr, 0.0022 gr/dscf	
New Steel International: Haverhill, OH	OH-0315 07-00587 (5/6/2008)	Conveyors, Hoppers, Screens to Rotary Hearth Furnace (227 tons/yr)	PM: Baghouse	1.4 lb/hr, 6.13 tons/yr, 0.0022 gr/dscf	
Minnesota Steel Industries	MN-0070 06100067-001 (9/7/2007)	Additive Handling	Baghouse	0.0025 gr/dscf	

Additive Preparation

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Fine additive production system (EU-1504)*	*cartridge filter*	*PM/PM10/PM2.5:* *0.002 gr/dscf* *0.004 lb/hr*	
Essar Steel Minnesota LLC	MN-0085 06100067-004 (5/10/2012)	Primary Grinding Mill Line 3	Baghouse w/ leak detection	PM/PM10/PM2.5: 0.002 gr/dscf 0.23 lb/hr	
United States Steel Corp	MN-0084 13700063-004 (12/6/2011)	Alternative fuels hammermill #1	Baghouse w/ leak detection	PM/PM10/PM2.5: 0.002 gr/dscf 0.41 lb/hr Opacity 5% (6 min avg)	
Alliant Energy	WI-0262 17-DCF-070 (6/30/2017)	Coal crusher house, P06	building enclosure, dust collection system, baghouse w/ leak detection	PM/PM10/PM2.5: 0.002 gr/dscf (filt PM10) 0.003 gr/dscf (ttl PM) 1.12 lb/hr 5% M9 opacity	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Donlin Gold LLC	AK-0084 AQ0934CPT 01 (6/30/2017)	Ore crushing and transfers (dust collector)	dust collector	PM/PM10/PM2.5: 0.010 gr/dscf	5100 tph
Wolverine Power Supply Cooperative Inc	MI-0400 317-07 (6/29/2011)	coal crushers	fabric filter	FPM: 2.0E-05 gr/dscf TPM10/TPM2.5: 2.76E-03 lb/hr 5% opacity (dust collector)	
State tracking system does not show a Part 70 permit for a source in the county identified in the RBLC entry. The source may not have been constructed. Therefore this is not considered representative of BACT for the proposed source.					
East Kentucky Power Cooperative Inc	KY-0100 V-05-070R3 (4/9/2010)	Coal crushing & silo storage	fabric filter	PM10: 0.005 gr/dscf	
Ohio River Clean Fuels LLC	OH-0317 02-22896 (11/20/2008)	Coal & biomass crusher houses (2)	baghouse with dust collector, totally enclosed crusher houses	1.20 lb/hr (ea baghouse) 5.30 tpy 0.005 gr/dscf	
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Martin Mariette Magnesia Specialties LLC	OH-0321 03-17089 (11/13/2008)	stone crushing and screening	maintain inherent moisture and include many vibratory feeders and material handling processes within tunnel enclosures	PM: 26.90 tpy PM10: 9.79 tpy 15% opacity (crushers, 6-min avg)	
Louisiana Generating LLC	LA-0223 PSD-LA-660 (M-1) (1/8/2008)	Fuel crusher house	fabric filter	0.04 lb/hr 0.06 tpy	
		Limestone silo and crusher		0.02 lb/hr 0.02 tpy	

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), BACT shall be the following:

(a)

(1)

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	**gr/dscf**	**lb/hr**
Railcar unloading, including: Receiving Pits 1 & 2 Receiving Bins 1 & 2 Drag Flight Feeders 1& 2 (EU-1000)	Baghouse EU-1000 (stack EU-1000) Water spray dust suppression (bins & feeders only)	PM	0.0022	0.12
		PM$_{10}$[1]	0.0022	0.12
		PM$_{2.5}$[1]	0.0022	0.12
Transfer station, including: Unloading Conveyor (EU-1001)	Baghouse EU-1001 (stack EU-1001)	PM	0.002	0.16
		PM$_{10}$[1]	0.002	0.16
		PM$_{2.5}$[1]	0.002	0.16

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	gr/dscf	lb/hr
Coal storage enclosure 1, including Conveyor 1 Stacker 1 Boom/Chute Stockpiles #1A & #1B Reclaimer 1 Coal storage enclosure 2, including: Conveyor 2 Stacker 2 Boom/Chute Stockpiles #2A & #2B Reclaimer 2 Reclaim transfer station, including: Conveyor 6 Conveyor 7 Conveyor 9	Baghouse EU-1006 (stack EU-1006)	PM	0.002	0.11
		PM_{10}[1]	0.002	0.11
		$PM_{2.5}$[1]	0.002	0.11
Coal drying loop purge, including: Conveyor 8 Coal mill & pulverizer Coal Dryer	Loop Purge Baghouse (stack EU-1008)	PM	0.002	0.26
		PM_{10}[1]	0.002	0.26
		$PM_{2.5}$[1]	0.002	0.26
Enclosed screw conveyor to Block 2000 feed premix drum	Coal Handling System Filter (stack EU-2005)	PM	0.002	0.003
		PM_{10}[1]	0.002	0.003
		$PM_{2.5}$[1]	0.002	0.003

Notes:
1. *PM_{10} and $PM_{2.5}$ include both filterable and condensable.*

(2) There shall be no (0%) visible emissions from the entrance and exit doors of the unloading enclosure at any time.

(b) Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the material handling operations shall be as follows:

(1)

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	gr/dscf	lb/hr
Coarse additive silo, T34 (EU-1501)	Baghouse EU-1501 (stack EU-1501)	PM	0.002	0.016
		PM_{10}[1]	0.002	0.016
		$PM_{2.5}$[1]	0.002	0.016

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	gr/dscf	lb/hr
Fine additive silo, T33 (EU-1502)	Baghouse EU-1502 (stack EU-1502)	PM	0.002	0.018
		PM_{10}[1]	0.002	0.018
		$PM_{2.5}$[1]	0.002	0.018
Na_2S silo, T35 (EU-1503)	Baghouse EU-1503 (stack EU-1503)	PM	0.002	0.013
		PM_{10}[1]	0.002	0.013
		$PM_{2.5}$[1]	0.002	0.013
Fine additive production system	Baghouse EU-1504 (stack EU-1504)	PM	0.002	0.004
		PM_{10}[1]	0.002	0.004
		$PM_{2.5}$[1]	0.002	0.004
Coarse additive screw conveyor	Coarse additive system filter (stack EU-2006)	PM	0.002	0.004
		PM_{10}[1]	0.002	0.004
		$PM_{2.5}$[1]	0.002	0.004
Fine additive transfer system	Fine additive system filter (stack EU-2007)	PM	0.002	0.004
		PM_{10}[1]	0.002	0.004
		$PM_{2.5}$[1]	0.002	0.004
Na_2S slurry preparation system	Na_2S handling system filter (stack EU-2008)	PM	0.002	0.001
		PM_{10}[1]	0.002	0.001
		$PM_{2.5}$[1]	0.002	0.001
Residue bulk container loading and residue transfer conveyors (EU-5009)	Filter EU-5009 (stack EU-5009)	PM	0.002	0.001
		PM_{10}[1]	0.002	0.001
		$PM_{2.5}$[1]	0.002	0.001
Residue rail storage silo (EU-5010), loading hoppers (EU-5005, EU-5006), and residue transfer conveyors	Filter EU-5010 (stack EU-5010)	PM	0.002	0.003
		PM_{10}[1]	0.002	0.003
		$PM_{2.5}$[1]	0.002	0.003
Residue swing storage silo (EU-5011), loading hoppers (EU-5007, EU-5008), and residue transfer conveyors	Filter EU-5011 (stack EU-5011)	PM	0.002	0.003
		PM_{10}[1]	0.002	0.003
		$PM_{2.5}$[1]	0.002	0.003
Lime silo (EU-6501)	Filter EU-6501 (stack EU-6501)	PM	0.002	0.01
		PM_{10}[1]	0.002	0.01
		$PM_{2.5}$[1]	0.002	0.01

Notes:
1. PM_{10} and $PM_{2.5}$ include both filterable and condensable.

(2) Transfers from the loading hoppers to transports shall employ choke flow-practices

(3) There shall be no visible emissions from transfers from the loading hoppers and from hoppers to transports.

BACT Analysis
Process fuel gas-fired heaters and boiler

PM/PM10/PM2.5

Step 1: Identify Potential Control Technologies

PM/PM10/PM2.5 emissions can be controlled with the following control technologies:

(1) Good Combustion Practices

Step 2: Eliminate Technically Infeasible Options

A search of the USEPA's RACT/BACT/LAER Clearinghouse indicates the use of good combustion practice for gas-fired combustion units is the best control for PM/PM10/PM2.5 emissions. Natural gas combustion is already efficient. It is possible to achieve PM/PM10/PM2.5 reductions from an add-on control device; however, any add-on control technology would not be cost effective since the PM/PM10/PM2.5 concentration in these units is relatively low. Good Combustion Practices are a technically feasible option.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Combustion Units (<100 MMBtu/hr) - PM/PM10/PM2.5

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-1007* *Coal milling and drying heater*	gas fuel, GCP[2]	PM (filterable): 0.11 lb/hr 0.0019 lb/MMBtu PM10: 0.42 lb/hr 0.0075 lb/MMBtu PM2.5: 0.42 lb/hr 0.0075 lb/MMBtu	*55.80*
		EU-2002 *Treat gas heater*		PM (filterable): 0.10 lb/hr 0.0019 lb/MMBtu PM10: 0.40 lb/hr 0.0075 lb/MMBtu PM2.5: 0.40 lb/hr 0.0075 lb/MMBtu	*52.80*
		EU-2003 *Vacuum column feed heater*		PM: 1.71E-02 lb/hr 0.0019 lb/MMBtu PM10: 6.75E-02 lb/hr 0.0075 lb/MMBtu PM2.5: 6.75E-02 lb/hr 0.0075 lb/MMBtu	*9.00*
		EU-6000 *Boiler*		PM (filterable): 0.13 lb/hr 0.0019 lb/MMBtu PM10: 0.53 lb/hr 0.0075 lb/MMBtu PM2.5: 0.53 lb/hr 0.0075 lb/MMBtu	*68.50*
Holly Refinery & Marketing-Tulsa LLC	OK-0167 2012-1062-C(M-1)PSD (4/20/2015)	Process heaters	gas fuel	PM10: 0.0075 lb/MMBtu PM2.5: 0.0075 lb/MMBtu	10.00 25.00 42.00 50.00
Holly Refinery & Marketing-Tulsa LLC	OK-0166 2010-599-C(M-3) (4/20/2015)	Process heater (refinery fuel gas)	gas fuel	PM10: 0.0075 lb/MMBtu PM2.5: 0.0075 lb/MMBtu	76.00
ExxonMobil Oil Corp.	TX-0832 PSDTX768M1, PSDTX799, PSDTX802 (1/9/2018)	F-2001 Kero HDT Charge Heater and F-2002 Kero HDT Stripper Reboiler (natural gas/refinery gas)	good combustion and use of gaseous fuel	PM: 0.67 lb/hr PM10: 0.67 lb/hr PM2.5: 0.67 lb/hr *(all filterable)* *(equivalent to 0.0078 lb/MMBtu)*	85.50
		F-3001 Diesel DHDT charge heater & F-3002 diesel DHDT stripper reboiler (natural gas /refinery gas)		PM: 0.49 lb/hr PM10: 0.49 lb/hr PM2.5: 0.49 lb/hr *(all filterable)* *(equivalent to 0.0074 lb/MMBtu)*	66.50

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Process heaters (refinery fuel gas)	-	PM/PM10: 0.08 lb/MMBtu	-
		#2 Hydrogen Unit heater	-	PM/PM10: 0.011 lb/MMBtu	-
		Hydrogen Plant heater	-	PM/PM10: 0.0116 lb/MMBtu	-
Sasol Chemicals (USA) LLC	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	DW reactor feed heaters (EQT 738 & 775) (process gas)	gas fuel, GCP	PM10: 0.46 lb/hr 1.54 tpy 0.0075 lb/MMBtu PM2.5: 0.46 lb/hr 1.54 tpy 0.0075 lb/MMBtu	56.80
		Base oils DW reactor feed heater (EQT 776) (process gas)		PM10: 0.26 lb/hr 0.84 tpy 0.0075 lb/MMBtu PM2.5: 0.26 lb/hr 0.84 tpy 0.0075 lb/MMBtu	31.00
		HC reactor feed heaters (EQT 736 & 754) (process gas)		PM10: 0.56 lb/hr 1.92 tpy 0.0075 lb/MMBtu PM2.5: 0.56 lb/hr 1.92 tpy 0.0075 lb/MMBtu	70.80
		Process heater (EQT 702) (process gas)		PM10: 0.58 lb/hr 2.01 tpy 0.0075 lb/MMBtu PM2.5: 0.58 lb/hr 2.01 tpy 0.0075 lb/MMBtu	73.80
		Base oils light vacuum feed heater (EQT 777) (process gas)		PM10: 0.56 lb/hr 1.94 tpy 0.0075 lb/MMBtu PM2.5: 0.56 lb/hr 1.94 tpy 0.0075 lb/MMBtu	71.20
		Base oils heavy vacuum feed heater (EQT 778)		PM10: 0.11 lb/hr 0.27 tpy 0.0075 lb/MMBtu PM2.5: 0.11 lb/hr 0.27 tpy 0.0075 lb/MMBtu	10.00
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Reactor feed heater (EQT 1160)	gas fuel, GCP	PM10: 0.13 lb/hr 0.49 tpy 0.0075 lb/MMBtu PM2.5: 0.13 lb/hr 0.49 tpy 0.0075 lb/MMBtu	18.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
	LA-0298 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 772) (process gas)		PM10: 0.30 lb/hr 1.08 tpy 0.0075 lb/MMBtu PM2.5: 0.30 lb/hr 1.08 tpy 0.0075 lb/MMBtu	40.00
	LA-0302 PSD-LA-779 (5/23/2014)	Process heat boilers (EQT 1008 & 1009)		PM10: 0.58 lb/hr 1.87 tpy 0.0075 lb/MMBtu PM2.5: 0.58 lb/hr 1.87 tpy 0.0075 lb/MMBtu	78.00 ea
Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-1 (natural gas and process fuel gas)	GCP	-	36.00
		heater 94-21			48.00
		heater 94-29			75.00
		heater/reboiler 2004-1			86.00
		heater/reboiler 2004-2			24.00
		heater/reboiler 2004-3			52.00
		heater/reboiler 2004-4			86.00
		heater/reboiler 2005-8			100.00
		heater/reboiler 2005-9			83.00
		heater/reboiler 2005-23			100.00
		heater/reboiler 2005-24			83.00
		CPF heater H-39-03	GCP	PM10: 0.0074 lb/MMBtu	68.00
		CPF heater H-39-02			90.00
		DHT heater 4-81	gas fuel	-	70.00
		DHT heater 5-81			70.00

Notes:

1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer’s recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.*

Combustion Units (>100 MMBtu/hr) - PM/PM_{10}/$PM_{2.5}$

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-2001* *Feed heater*	gas fuel, GCP[2]	PM (filterable): 0.24 lb/hr 0.0019 lb/MMBtu PM10: 0.96 lb/hr 0.0075 lb/MMBtu PM2.5: 0.96 lb/hr 0.0075 lb/MMBtu	*128.40*
		EU-2004 *Fractionator heater*		PM (filterable): 0.30 lb/hr 0.0019 lb/MMBtu PM10: 1.17 lb/hr 0.0075 lb/MMBtu PM2.5: 1.17 lb/hr 0.0075 lb/MMBtu	*156.00*
Holly Refinery & Marketing-Tulsa LLC	OK-0167 2012-1062-C(M-1)PSD (4/20/2015)	CDU atmospheric tower heater (refinery fuel gas)	gas fuel	PM10: 0.0075 lb/MMBtu PM2.5: 0.0075 lb/MMBtu	248.00
	OK-0170 2012-1062-C(M-6) (11/12/2015)	Process heater (H-205) (refinery fuel gas)	gas fuel, GCP	PM2.5: 0.0075 lb/MMBtu	100.00
Sasol Chemicals (USA) LLC	LA-0290 PSD-LA-778 (5/23/2014) (GTL unit)	Hot oil heater (process gas)	gas fuel, GCP	PM10: 1.56 lb/hr 5.70 tpy 0.0075 lb/MMBtu PM2.5: 1.56 lb/hr 5.70 tpy 0.0075 lb/MMBtu	171.00
	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	Fractionator feed heaters (EQT 737 & 774) (process gas)		PM10: 1.89 lb/hr 6.76 tpy 0.0075 lb/MMBtu PM2.5: 1.89 lb/hr 6.76 tpy 0.0075 lb/MMBtu	248.70
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 1161) (process gas)	gas fuel, GCP	PM10: 1.79 lb/hr 6.53 tpy 0.0075 lb/MMBtu PM2.5: 1.79 lb/hr 6.53 tpy 0.0075 lb/MMBtu	240.00
Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-4 (refinery fuel gas)	comply with 40 CFR 60, subparts NNN and RRR	-	108.00
		heater 2008-5			123.00
		heater 2008-7			122.00
		heater 2008-9			122.00
		heater/reboiler 6-81	gas fuel, GCP	-	135.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Shintech Louisiana LLC	LA-0204 PSD-LA-709(M-1) (2/27/2009)	Boilers A & B Boilers C & D	natural gas, GCP	0.005 lb/MMBtu	250 ea
This source is in SIC code 2821, not 2911 like the proposed source. RBLC process code is 12.390, for "other gaseous fuels and gaseous fuel mixtures" but entries specify that the units burn natural gas. Therefore these entries may not represent BACT for the proposed source and have not been considered.					

Notes:

1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.*

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the fuel combustion units listed in the table below shall be as follows:

Description	Unit ID
Coal dryer heater	EU-1007
Feed heater	EU-2001
Treat gas heater	EU-2002
Vacuum column feed heater	EU-2003
Fractionator heater	EU-2004
Package boiler	EU-6000

(a) The units shall burn only natural gas and process off-gas.

(b) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(c) Particulate matter emissions shall not exceed:

Emission Limitations			
Unit ID	**Pollutant**	**lb/MMBtu**	**lb/hr**
EU-1007	$PM_{FILTERABLE}$	0.0019	0.11
	PM_{10}	0.0075	0.42
	$PM_{2.5}$	0.0075	0.42
EU-2001	$PM_{FILTERABLE}$	0.0019	0.24
	PM_{10}	0.0075	0.96
	$PM_{2.5}$	0.0075	0.96
EU-2002	$PM_{FILTERABLE}$	0.0019	0.10
	PM_{10}	0.0075	0.40
	$PM_{2.5}$	0.0075	0.40

Emission Limitations			
Unit ID	**Pollutant**	**lb/MMBtu**	**lb/hr**
EU-2003	$PM_{FILTERABLE}$	0.0019	1.71E-02
	PM_{10}	0.0075	6.75E-02
	$PM_{2.5}$	0.0075	6.75E-02
EU-2004	$PM_{FILTERABLE}$	0.0019	0.30
	PM_{10}	0.0075	1.17
	$PM_{2.5}$	0.0075	1.17
EU-6000	$PM_{FILTERABLE}$	0.0019	0.13
	PM_{10}	0.0075	0.51
	$PM_{2.5}$	0.0075	0.51

Notes:
1. tons/yr = tons per twelve (12) consecutive month period

SO_2

Step 1: Identify Potential Control Technologies

Sulfur Dioxide (SO_2) emissions result from the oxidation of fuel-bound sulfur, with emissions dependent upon the sulfur content of the fuel. Sulfur Dioxide (SO_2) emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(a) Flue Gas Desulfurization (FGD) System);
  (1) Wet Scrubbing
  (2) Spray Dryer Absorption (SDA)
  (3) Dry Sorbent Injection (DSI)
(b) Fuel Specification.
(c) Good Combustion Practices

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Flue Gas Desulfurization (FGD) System (Dry and Wet Scrubbers)
A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. FGD is an established technology. FGD typically operates at a temperature of approximately 300°F to 700°F (wet) and 300°F to 1830°F (dry). The FGD has a waste stream inlet pollutant concentration of 2,000 ppmv. Absorption of SO_2 is accomplished by the contact between the exhaust and an alkaline reagent, which results in the formation of neutral salts. Wet systems employ reagents using packed or spray towers and generate wastewater streams, while dry systems inject slurry reagent into the exhaust stream to react, dry and be removed downstream by particulate control equipment. Chlorine emissions can result in salt deposition within the absorber and in downstream equipment. Wet systems may require flue gas re-heating downstream of the absorber to prevent corrosive condensation. Inlet streams for dry systems must be cooled as appropriate, and dry systems require use of particulate controls to collect the solid netural salts.

(1) Wet Scrubbing Wet scrubbers are regenerative processes which are designed to maximize contact between the exhaust gas and an absorbing liquid. The exhaust gas is scrubbed with a 5 - 15 percent slurry, comprised of lime (CaO) or limestone ($CaCO_3$) in suspension. The SO_2 in the exhaust gas reacts with the CaO or $CaCO_3$ to form calcium sulfite ($CaSO_3.2H_2O$) and calcium

sulfate ($CaSO_4$). The scrubbing liquor is continuously recycled to the scrubbing tower after fresh lime or limestone has been added.

The types of scrubbers which can adequately disperse the scrubbing liquid include packed towers, plate or tray towers, spray chambers, and venturi scrubbers. In addition to calcium sulfite/sulfate, numerous other absorbents are available including sodium solutions and ammonia-based solutions.

(2) Spray Dryer Absorption (SDA) - An alternative to wet scrubbing is a process known as dry scrubbing, or spray-dryer absorption (SDA). As in wet scrubbing, the gas-phase SO_2 is removed by intimate contact with a suitable absorbing solution. Typically, this may be a solution of sodium carbonate (Na_2CO_3) or slaked lime [$Ca(OH)_2$]. In SDA systems the solution is pumped to rotary atomizers, which create a spray of very fine droplets. The droplets mix with the incoming SO_2-laden exhaust gas in a very large chamber and subsequent absorption leads to the formation of sulfites and sulfates within the droplets. Almost simultaneously, the sensible heat of the exhaust gas which enters the chamber evaporates the water in the droplets, forming a dry powder before the gas leaves the spray dryer. The temperature of the desulfurized gas stream leaving the spray dryer is now approximately 30 - 50^{o}F above its dew point.

The exhaust gas from the SDA system contains a particulate mixture which includes reacted products. Typically, baghouses employing teflon-coated fiberglass bags (to minimize bag corrosion) are utilized to collect the precipitated particulates.

(3) Dry Sorbent Injection (DSI) - This control option typically involves the injection of dry powders into either the furnace or post-furnace region of utility-sized boilers. This process was developed as a lower cost option to conventional FGD technology. Since the sorbent is injected directly into the exhaust gas stream, the mixing offered by the dry scrubber tower is not realized. The maximum efficiency realized for this SO_2 control technology is estimated to be fairly nominal. It is felt that if sufficient amounts of reactants are introduced into the flue gas, there is a possibility of some degree of mixing and reaction. The science is inexact and the coupling of reactant dosage and in-flue mixing which impacts the SO_2 control efficiency is susceptible to variability in SO_2 concentrations.

Dry Sorbent Injection
A post-combustion technology in which a calcium or sodium-based sorbent reacts with SO_2 and SO_3 and is removed downstream by particulate control equipment. The system requires use of particulate controls to collect the reaction solids. Dry sorbent injection is not listed in the RBLC as BACT for the control of SO_2 emissions for auxiliary boilers. Technology has not been applied to natural gas combustion turbines due to very low SO_2 emissions. Controls would not provide any measurable emission reduction.

Fuel Specifications
Combusting only clean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating SO_2 emissions.

Step 2: Eliminate Technically Infeasible Options:

FGD systems are not listed in the RBLC as BACT for the control of SO_2 emissions for process heaters and/or boilers. Technology has not been applied to natural gas units due to very low SO_2 emissions. Controls would not provide any measurable emission reduction and would not be economically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Good Combustion Practices and use of low-sulfur fuel gas are the only feasible option.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Combustion Units - SO_2

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-1007 Coal milling and drying heater*	*The average sulfur content of the fuel gas combusted shall not exceed 0.005 gr/scf per twelve (12) consecutive month period with compliance determined at the end of each month.*	*0.35 tpy*	*55.80*
		EU-2001 Feed heater		*0.80 tpy*	*128.40*
		EU-2002 Treat gas heater		*0.33 tpy*	*52.80*
		EU-2003 Vacuum column feed heater		*0.06 tpy*	*9.00*
		EU-2004 Fractionator heater		*0.97 tpy*	*156.00*
		EU-6000 Boiler		*0.42 tpy*	*68.50*
The source has proposed a more restrictive limit for fuel gas sulfur content than entries in the RBLC database. Therefore, this is determined to be BACT.					
ExxonMobil Oil Corp.	TX-0832 PSDTX768M1, PSDTX799, PSDTX802 (1/9/2018)	F-1001 Crude Charge Furnace (natural gas/refinery gas)	use low sulfur gas fuel	162 ppmvd hourly 60 ppmvd annual	630.80
		F-2001 Kero HDT Charge Heater and F-2002 Kero HDT Stripper Reboiler (natural gas/refinery gas)	good combustion and use of gaseous fuel		85.50
		F-3001 Diesel DHDT charge heater & F-3002 diesel DHDT stripper reboiler (natural gas /refinery gas)			66.50
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Process heaters	-	H_2S limited: 160 ppmv @ 0% O_2 (3-hr) 60 ppmv @ 0% O_2 (365 day)	-
Sasol Chemicals (USA) LLC	LA-0288 PSD-LA-778 (5/23/2014) (GTL unit)	HP SH Steam Boilers (EQT 631, 632, & 633) (process gas)	use of gaseous fuel with a sulfur content of no more than 0.005 gr/scf (ann avg)	24.22 lb/hr max (ea) 1.67 tpy annual (ea)	408.40
		Process Heaterr (EQT 690, 691, 692, 751, 752, &753) (process gas)		25.25 lb/hr max (ea) 2.28 tpy annual (ea) 0.0015 lb/MMBtu ann avg	424.80
	LA-0290 PSD-LA-778 (5/23/2014) (GTL unit)	Hot oil heater (EQT 623) (process gas)		12.34 lb/hr 1.12 tpy	171.00
	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	Fractionator feed heaters (EQT 737 & 774) (process gas)		14.89 lb/hr 1.33 tpy	248.70

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
		DW reactor feed heaters (EQT 738 & 775) (process gas)		3.61 lb/hr 0.30 tpy	56.80
		Base oils DW reactor feed heater (EQT 776) (process gas)		2.09 lb/hr 0.17 tpy	31.00
		HC reactor feed heaters (EQT 736 & 754) (process gas)		4.43 lb/hr 0.38 tpy	70.80
		Process heater (EQT 702) (process gas)		4.61 lb/hr 0.40 tpy	73.80
		Base oils light vacuum feed heater (EQT 777) (process gas)		4.45 lb/hr 0.38 tpy	71.20
		Base oils heavy vacuum feed heater (EQT 778)		0.86 lb/hr 0.05 tpy	10.00
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0301 PSD-LA-779 (5/23/2014)	Utility Steam Boiler Nos. 1-3 (EQTs 967, 968, &969) (process gas)	use of gaseous fuel with a sulfur content of no more than 0.005 gr/scf (ann avg)	1.98 lb/hr max (ea) 10.43 tpy ann max combined	662.00
		Furnace Nos. 1-8 (EQTs 971 - 978) (process gas)		1.92 lb/hr max (ea) 28.08 tpy ann max comb	654.00
	LA-0303 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 1161) (process gas)		14.12 lb/hr 1.29 tpy	240.00
		Reactor feed heater (EQT 1160)		1.06 lb/hr 0.10 tpy	18.00
	LA-0298 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 772) (process gas)		2.33 lb/hr 0.21 tpy	40.00
	LA-0302 PSD-LA-779 (5/23/2014)	Process heat boilers (EQT 1008 & 1009)		4.60 lb/hr 0.37 tpy	78.00
Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Lima Refining Co.	OH-0362 P0114527 (12/23/2013)	Crude Distillation Unit II Heater (refinery fuel gas or natural gas)	H2S concentration <= 230 mg/dscm (0.1 gr/dscf) (equiv to 162 ppmvd) or SO2 <= 20 ppmvd @0% xs air(3 hr avg) <= 60ppmvd H2S or SO2 ,= 8 ppmvd @ 0% xs air (365 day avg)		624.00
		Vacuum unit II heater (refinery fuel gas or natural gas)			102.30
Sinclair Wyoming Refining Co.	WY-0071 MD-12620 (10/15/2012)	581 crude heater (refinery fuel gas)		follow Subpart Ja fuel gas H2S limits	233.00
		583 vacuum heater			64.20
		Naphtha splitter heater			46.30
		Hydrocracker H5 heater			44.90
		#1 HDS heater			33.40
		BSI heater			50.00
BP Exploration (Alaska)	AK-0074 AQ0181CPT 07 (7/29/2011)	Combustion (fuel gas)		1,000 ppmv (H2S)	98.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Valero Refining - New Orleans, LLC	LA-0213 PSD-LA-619 (M5) (11/17/2009)	Heater F-72-703 (7-81)	fueled by natural gas or refinery fuel gas with H2S <= 100 ppmv (annual average)	-	633.00
		Boilers (2008-10, 2008-11, 2008-40)	fueled by natural gas or refinery fuel gas with H2S <= 100 ppmv (annual average) or process fuel gas with H2S <= 10 ppmv (annual average)	-	715.00 ea
		Boilers (94-43 & 94-45)	use of pipeline quality natural gas or refinery fuel gas with a H2S concentration < 100 ppmv (annual average)	9.43 lb/hr max	354.00 ea
		heater 2008-1 (natural gas and process fuel gas)	use natural gas or process fuel gases with H2S concentration < 10 ppmv (ann avg)		36.00
		heater 2008-2			880.00
		heater 2008-3			641.00
		heater 2008-4			108.00
		heater 2008-5			123.00
		heater 2008-6			803.00
		heater 2008-7			122.00
		heater 2008-8			803.00
		heater 2008-9			122.00
		heater 94-21			48.00
		heater 94-29			75.00
		heater/reboiler 6-81			135.00
		heater/reboiler 2004-1			86.00
		heater/reboiler 2004-2			24.00
		heater/reboiler 2004-3			52.00
		heater/reboiler 2004-4			86.00
		heater/reboiler 2004-7			885.00
		heater/reboiler 2004-8			885.00
		heater/reboiler 2005-1			1,274.00
		heater/reboiler 2005-2			744.00
		heater/reboiler 2005-3			555.00
		heater/reboiler 2005-8			100.00
		heater/reboiler 2005-9			83.00
		heater/reboiler 2005-10			336.00
		heater/reboiler 2005-22			261.00
		heater/reboiler 2005-23			100.00
		heater/reboiler 2005-24			83.00
		heater/reboiler 2005-25			336.00
		CPF heater H-39-03			68.00
		CPF heater H-39-02			90.00
		DHT heater 4-81			70.00
		DHT heater 5-81			70.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Sunoco, Inc.	OH-0308 04-01447 (2/23/2009)	Boiler (2) (refinery process gas, natural gas, residual #6 oil, and CO from FCCU)		9.15 lb/hr ea 40.60 tpy ea 0.0270 lb/MMBtu operating w/o FCCU	374.00
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Boiler (natural gas and tail gas)	"good combustion practice"	2.00 lb/hr (3 hr avg) 8.9 tpy 0.60 lb/MMSCF	1200.00
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Citgo Petroleum Co.	LA-0234 PSD-LA-691(M1) (1/26/2007)	3(XXXIV)7-201 furnace B-201	low sulfur concentration in the fuel gas 475 ppm max 218.4 ppm avg	5.08 lb/hr	56.90
		3(XXXIV)7-202 furnace B-202		5.08 lb/hr	56.90
		3(XXXIV)7-101 furnace B-101		5.08 lb/hr	62.80
		3(XXXIV)7-102 furnace B-102		5.08 lb/hr	62.80
		3(XXXIV)7-103 reboiler B-103		3.10 lb/hr	50.00
		3(XXXIV)7-203 reboiler B-203		3.10 lb/hr	50.00

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for SO_2 for the fuel combustion units listed in the table below shall be as follows:

Description	Unit ID
Coal dryer heater	EU-1007
Feed heater	EU-2001
Treat gas heater	EU-2002
Vacuum column feed heater	EU-2003
Fractionator heater	EU-2004
Package boiler	EU-6000

(a) The units shall burn only natural gas and process off-gas.

(b) The average sulfur content of the fuel gas combusted shall not exceed 0.005 gr/scf per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) SO_2 emissions shall not exceed:

SO_2 Emission Limitations	
Unit ID	**tpy**
EU-1007	0.35
EU-2001	0.80
EU-2002	0.33
EU-2003	0.06
EU-2004	0.97
EU-6000	0.42

NOx

Step 1: Identify Potential Control Technologies

NOx emissions can be controlled with the following control technologies:

Post-combustion controls:

(1) Selective Catalytic Reduction (SCR)
(2) Selective Non-Catalytic Reduction (SNCR)

Combustion controls:
(3) Low NOx Burner (LNB)/Ultra low-Nox burner (ULNB)
(4) Flue Gas Recirculation (FGR)
(5) Good Combustion Practices

Selective Catalytic Reduction (SCR)
Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to water and N_2. Under optimal conditions, SCR has a removal efficiency up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR can operate in a flue gas window ranging from 480°F to 800°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. In this particular service, the minimum target temperature is approximately 750ºF. Temperatures below the optimum decrease catalyst activity and allow NH3 to slip through; above the optimum range, ammonia will oxidize to form additional NOx. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH3:NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

Selective Non-Catalytic Reduction (SNCR)
With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2000°F, without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction.

At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of competing reactions for the direct oxidation of ammonia that forms NOx becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_x control performance requires that the furnace exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range and steady operation within that temperature window.

Low NOx Burners (LNB)
Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible.

Flue Gas Recirculation (FGR)
Recirculating a portion of the flue gas to the combustion zone can lower the peak flame temperature and result in reduced thermal NOx production. The flue gas recirculation (FGR) can be highly effective technique for lowering NOx emissions from burners and it's relatively inexpensive to apply. FGR lowers NOx emissions in two ways; the cooler, relatively inert, recirculated flue gases act as heat sink, absorbing heat from the flame and lowering peak flame temperatures and when mixed with the combustion air, recirculated flue gases lower the average oxygen content of the air, starving the NOx-forming reactions for one of the needed ingredients.

Step 2: Eliminate Technically Infeasible Options:

Technology	BACT Evaluation
Selective Catalytic Reduction (SCR) Technically Feasible – **Yes**	Selective Catalytic Reduction (SCR) is technically feasible.
Selective Non-Catalytic Reduction (SNCR) Technically Feasible – **No**	Riverview will operate at a wide range of load levels, with lower levels potentially unable to provide a temperature profile that maintains the range needed for effective control for sufficient residence time to achieve proper control. Some ammonia will be emitted. The combustion units used at Riverview combust a combination of gaseous fuels that are proportionally variable over relatively short time periods and results in short term NOx loading variations. This variability woks against the limited temperature flexibility and difficulty of SNCR in adjusting to short term changes maintaining consistent NOx control during operation of these units. For these reasons, the SNCR is technically infeasible.
Low NOx Burner (LNB) Technically Feasible - **Yes**	LNB/ULNB is technically feasible.
Flue Gas Recirculation (FGR) Technically Feasible – **Yes**	Flue Gas Recirculation (FGR) is technically feasible.
Good Combustion Practices Technically Feasible – **Yes**	Good Combustion Practices are technically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Control Option	Expected Control Efficiency
LNB/ULNB	40-85%
SCR	70%-90%
SNCR	30%-50%
FGR	15%-50%

Step 4: Evaluate the Most Effective Controls and Document the Results

The following tables summarize other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Combustion Units (<100 MMBtu/hr) - NOx

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-1007 Coal milling and drying heater*	*ULNB (≤0.030 lb NOx/MMBtu), GCP*[2]	*1.67 lb/hr*	*55.80*
		EU-2002 Treat gas heater		*1.58 lb/hr*	*52.80*
		EU-2003 Vacuum column feed heater		*0.27 lb/hr*	*9.00*
		EU-6000 Boiler		*2.06 lb/hr*	*68.50*
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Coker Unit heater and #2 Hydrogen Unit heater	-	0.03 lb/MMBtu	-
Holly Refinery & Marketing-Tulsa LLC	OK-0167 2012-1062-C(M-1)PSD (4/20/2015)	Process heaters	ULNB	0.030 lb/MMBtu	10.00
					25.00
					42.00
					50.00
Holly Refinery & Marketing-Tulsa LLC	OK-0166 2010-599-C(M-3) (4/20/2015)	Process heater (refinery fuel gas)	UNLB	0.030 lb/MMBtu (3-hr)	76.00
Indorama Ventures Olefins LLC	LA-0314 PSD-LA-813 (8/3/2016)	Dryer regenerator heater-005	ULNB, GCP	0.060 lb/MMBtu (3, 1-hr test avg)	29.00
This source is in SIC code 2821, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Equistar Chemicals LP	LA-0295 PSD-LA-806 (7/12/2016)	Firetube boilers Nos. 1 & 2 (EQT 324 &325)	FGR, GCP[2]	2.75 lb/hr max *(equiv to 0.04 lb/MMBtu)* 30 ppmvd @ 3% O2 (ann avg)	63.00
This source is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Sasol Chemicals (USA) LLC	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	DW reactor feed heaters (EQT 738 & 775) (process gas)	ULNB	2.30 lb/hr 7.87 tpy 0.038 lb/MMBtu	56.80
		Base oils DW reactor feed heater (EQT 776) (process gas)		1.35 lb/hr 4.30 tpy 0.038 lb/MMBtu	31.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
		HC reactor feed heaters (EQT 736 & 754) (process gas)		2.86 lb/hr 9.82 tpy 0.038 lb/MMBtu	70.80
		Process heater (EQT 702) (process gas)		2.98 lb/hr 10.23 tpy 0.038 lb/MMBtu	73.80
		Base oils light vacuum feed heater (EQT 777) (process gas)		2.88 lb/hr 9.87 tpy 0.038 lb/MMBtu	71.20
		Base oils heavy vacuum feed heater (EQT 778)		0.55 lb/hr 1.39 tpy 0.038 lb/MMBtu	10.00
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Reactor feed heater (EQT 1160)	ULNB	0.68 lb/hr 2.50 tpy 0.038 lb/MMBtu	18.00
	LA-0298 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 772) (process gas)		1.50 lb/hr 5.49 tpy 0.038 lb/MMBtu	40.00
	LA-0302 PSD-LA-779 (5/23/2014)	Process heat boilers (EQT 1008 & 1009)		2.97 lb/hr 9.55 tpy 0.038 lb/MMBtu	78.00
Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Diamond Shamrock Refining Co, LP	TX-0720 9708, PSDTX861M3 (12/20/2013)	Vacuum heater	LNB	0.035 lb/MMBtu	88.00
		Naphtha hydrotreater charge heater		0.038 lb/MMBtu	33.30
Sinclair Wyoming Refining Co.	WY-0071 MD-12620 (10/15/2012)	583 vacuum heater	ULNB	1.90 lb/hr 0.030 lb/MMBtu (3-hr avg)	64.20
		Naphtha splitter heater		1.60 lb/hr (3-hr avg) 7.1 tpy 0.035 lb/MMBtu (3-hr avg)	46.30
		Hydrocracker H5 heater		1.60 lb/hr (3-hr avg) 0.0350 lb/MMBtu (3-hr avg)	44.90
		#1 HDS heater		1.20 lb/hr (3-hr avg) 0.0350 lb/MMBtu (3-hr avg)	33.40
		BSI heater		1.30 lb/hr (3-hr avg) 5.50 tpy 0.025 lb/MMBtu (3-hr avg)	50.00
The BSI heater was never constructed and never tested, therefore the unit is not considered as establishing BACT.					
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-1 (natural gas and process fuel gas)	ULNB	0.040 lb/MMBtu (3, 1-hr test avg, air preheater) 0.030 lb/MMBtu (3, 1-hr test avg)	36.00
		heater 94-21	ULNB	not available	48.00
		heater 94-29	ULNB	not available	75.00
		heater/reboiler 2004-1	ULNB	0.040 lb/MMBtu (3, 1-hr test avg)	86.00
		heater/reboiler 2004-2			24.00
		heater/reboiler 2004-3			52.00
		heater/reboiler 2004-4			86.00
		heater/reboiler 2005-8			100.00
		heater/reboiler 2005-9			83.00
		heater/reboiler 2005-23			100.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
		heater/reboiler 2005-24			83.00
		CPF heater H-39-03	LNB	0.050 lb/MMBtu (3, 1-hr test avg)	68.00
		CPF heater H-39-02			90.00
		DHT heater 4-81	LNB	0.080 lb/MMBtu (3, 1-hr test avg)	70.00
		DHT heater 5-81			70.00
	LA-0265 PSD-LA-619(M7) (10/2/2012)	Boiler 401-F (refinery gas)	ULNB	0.040 lb/MMBtu	99.00
Medicine Bow Fuel & Power	WY-0066 CT-5873 (3/4/2009)	Auxiliary boiler (syngas)	LNB	3.20 lb/hr 14.20 tpy 0.050 lb/MMBtu	66.00
		HGT reactor charge heater		0.10 lb/hr 0.50 tpy 0.050 lb/MMBtu	2.22
Facility was not built.					
Conoco Phillips	OK-0136 2007-042-C PSD (2/9/2009)	NH-5 new no. 1 CTU tar stripper heater (refinery gas)	ULNB, 0.03 lb/MMBtu	2.94 lb/hr (365 day avg) 12.90 tpy (365 day avg)	98.00
		NH-3 new no. 4 CTU vacuum heater		1.39 lb/hr (365 day avg) 5.90 tpy (365 day avg)	45.00
Sunoco Inc (R&M)	PA-0256 06144 (1/29/2008)	IH-5 heater (refinery fuel gas)	ULNB (BACT & LAER)	8.60 tpy (365 ttl) 0.02 lb.MMBtu (3, 1-hr test)	98.00
This entry is LAER so it is not considered as establishing BACT.					

Notes:

1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.*

Combustion Units (>100 MMBtu/hr) - NOx

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-2001 Feed heater*	*ULNB (≤0.030 lb NOx/MMBtu), GCP*[2]	*3.85 lb/hr*	*128.40*
		EU-2004 Fractionator heater		*4.68 lb/hr*	*156.00*
Sinclair Wyoming Refining Co.	WY-0071 MD-12620 (10/15/2012)	581 crude heater (refinery fuel gas)	ULNB	7.00 lb/hr (3-hr avg) 0.030 lb/MMBtu (3-hr avg)	233.00
Holly Refinery & Marketing-Tulsa LLC	OK-0167 2012-1062-C(M-1)PSD (4/20/2015)	CDU atmospheric tower heater (refinery fuel gas)	ULNB	0.030 lb/MMBtu	248.00
	OK-0170 2012-1062-C(M-6) (11/12/2015)	Process heater (H-205) (refinery fuel gas)			100.00
Phillips 66 Co.	LA-0283 PSD-LA-696(M-3) (8/14/2015)	294-H-1 (EQT0017) (fuel gas)	ULNB w/ internal FGR	10.08 lb/hr 24.53 tpy 0.040 lb/MMBtu (ann avg)	168.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
M&G Resins USA LLC	TX-0671 108446/PSD TX1352 (12/1/2014)	Heat transfer fluid heaters (natural gas, biogas, and process waste gas)	SCR	12.40 tpy 0.020 lb/MMBtu	141.82 ea
This source is in SIC code 2821, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Sasol Chemicals (USA) LLC	LA-0290 PSD-LA-778 (5/23/2014) (GTL unit)	Hot oil heater (process gas)	ULNB	7.97 lb/hr 29.09 tpy 0.038 lb/MMBtu	171.00
	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	Fractionator feed heaters (EQT 737 & 774) (process gas)		9.62 lb/hr 34.49 tpy 0.038 lb/MMBtu	248.70
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 1161) (process gas)	ULNB	9.12 lb/hr 33.29 tpy 0.038 lb/MMBtu	240.00
Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Valero Energy Corp	DE-0020 AQM-003/00016 (2/26/2010)	Crude unit vacuum heater 21-H-2	SCR (RACT)	20.00 lb/hr (24 hr avg) 0.040 lb/MMBtu (3hr avg)	240.00
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-4 (refinery fuel gas)	ULNB	0.040 lb/MMBtu (3, 1-hr test avg, air preheater) 0.030 lb/MMBtu (3, 1-hr test avg)	108.00
		heater 2008-5			123.00
		heater 2008-7			122.00
		heater 2008-9			122.00
		heater/reboiler 6-81		0.040 lb/MMBtu (3, 1-hr test avg)	135.00
Shintech Louisiana LLC	LA-0204 PSD-LA-709(M-1) (2/27/2009)	Boilers A & B	LNB & FGR	0.040 lb/MMBtu	250 ea
		Boilers C & D			
Conoco Phillips	OK-0136 2007-042-C PSD (2/9/2009)	NH-1 new naphtha splitter reboiler	ULNB, 0.03 lb/MMBtu	3.94 lb/hr (365 day avg) 17.30 tpy (365 day avg)	131.00
		NH-4 new no. 1 CTU crude heater		3.37 lb/hr (365 day avg) 16.40 tpy (365 day avg)	125.00

Notes:

1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.*

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 the Best Available Control Technology (PSD BACT), shall be the following:

(a) The units shall burn only natural gas and process off-gas.

(b) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(c) The units shall use ultra-low-NOx burners.

(d) NOx emissions shall not exceed:

Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
EU-1007	0.030	1.67
EU-2001	0.030	3.85
EU-2002	0.030	1.58
EU-2003	0.030	0.27
EU-2004	0.030	4.68
EU-6000	0.030	2.06

VOC

Step 1: Identify Potential Control Technologies

VOC emissions can be controlled with the following control technologies:

(1) Thermal Oxidation
(2) Catalytic Oxidation
(3) Flares
(4) Good Combustion Practices

Step 2: Eliminate Technically Infeasible Options

VOC emissions from boilers/heaters are the result of incomplete fuel combustion. A search of the USEPA’s RACT/BACT/LAER Clearinghouse indicates the use of good combustion practice for gas-fired combustion units is the best control for VOC emissions. Natural gas combustion is already efficient. It is possible to achieve VOC reductions from an add-on control device; however, any add-on oxidation control technology would not be cost effective since the VOC concentration in these units is relatively low.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Combustion Units (<100 MMBtu/hr) - VOC

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-1007* *Coal milling and drying heater*	*GCP*[2]	*0.30 lb/hr* *0.0054 lb/MMBtu*	*55.80*
		EU-2002 *Treat gas heater*		*0.29 lb/hr* *0.0054 lb/MMBtu*	*52.80*
		EU-2003 *Vacuum column feed heater*		*0.05 lb/hr* *0.0054 lb/MMBtu*	*9.00*
		EU-6000 *Boiler*		*0.37 lb/hr* *0.0054 lb/MMBtu*	*68.50*
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-1 (natural gas and process fuel gas)	comply with 40 CFR 60, Subparts NNN and RRR	-	36.00
		heater 94-21	gas fuel, GCP	-	48.00
		heater 94-29			75.00
		heater/reboiler 2004-1			86.00
		heater/reboiler 2004-2			24.00
		heater/reboiler 2004-3			52.00
		heater/reboiler 2004-4			86.00
		heater/reboiler 2005-8			100.00
		heater/reboiler 2005-9			83.00
		heater/reboiler 2005-23			100.00
		heater/reboiler 2005-24			83.00
		CPF heater H-39-03		0.0054 lb/MMBtu	68.00
		CPF heater H-39-02			90.00
		DHT heater 4-81		-	70.00
		DHT heater 5-81			70.00
Indorama Ventures Olefins LLC	LA-0314 PSD-LA-813 (8/3/2016)	Dryer regenerator heater-005	GCP	0.0054 lb/MMBtu	29.00
This source is in SIC code 2821, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Coker Unit heater, #2 Hydrogen Unit heater, two existing Coker Unit heaters, Vacuum Unit heater	-	0.005 lb/MMBtu	-
This entry in RBLC is labeled as a draft determination, therefore it is not considered to establish BACT for the proposed source.					
Sasol Chemicals (USA) LLC	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	DW reactor feed heaters (EQT 738 & 775) (process gas)	GCP, 40 CFR 63, Subpart DDDDD tuneups	0.33 lb/hr 1.12 tpy 0.0054 lb/MMBtu	56.80
		Base oils DW reactor feed heater (EQT 776) (process gas)		0.19 lb/hr 0.61 tpy 0.0054 lb/MMBtu	31.00
		HC reactor feed heaters (EQT 736 & 754) (process gas)		0.41 lb/hr 1.39 tpy 0.0054 lb/MMBtu	70.80
		Process heater (EQT 702) (process gas)		0.42 lb/hr 1.45 tpy 0.0054 lb/MMBtu	73.80
		Base oils light vacuum feed heater (EQT 777) (process gas)		0.41 lb/hr 1.40 tpy 0.0054 lb/MMbtu	71.20
		Base oils heavy vacuum feed heater (EQT 778)		0.08 lb/hr 0.20 tpy 0.0054 lb/MMBtu	10.00
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
	LA-0303 PSD-LA-779 (5/23/2014)	Reactor feed heater (EQT 1160)	GCP, applicable provisions of 40 CFR 63, Subpart DDDDD	0.10 lb/hr 0.35 tpy 0.0054 lb/MMBtu	18.00
	LA-0298 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 772) (process gas)		0.21 lb/hr 0.78 tpy 0.0054 lb/MMBtu	40.00
	LA-0302 PSD-LA-779 (5/23/2014)	Process heat boilers (EQT 1008 & 1009)		0.42 lb/hr (ea) 1.36 tpy (comb)	78.00
Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					

Notes:

1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.*

Combustion Units (>100 MMBtu/hr) - VOC

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-2001* *Feed heater*	*GCP*[2]	*0.69 lb/hr* *0.0054 lb/MMBtu*	*128.40*
		EU-2004 *Fractionator heater*		*0.84 lb/hr* *0.0054 lb/MMBtu*	*156.00*
Phillips 66 Co.	LA-0283 PSD-LA-696(M-3) (8/14/2015)	Low sulfur gasoline feed heater no. 1, 294-H-1 (EQT0017) (fuel gas)	GCP	0.91 lb/hr 3.31 tpy *(equivalent to 0.0054 lb/MMBtu)*	168.00
M&G Resins USA LLC	TX-0671 108446/PSD TX1352 (12/1/2014)	Heat transfer fluid heaters (natural gas, biogas, and process waste gas)	fuel gas firing	3.35 tpy 0.0054 lb/MMBtu	141.82 ea
This source is in SIC code 2821, not 2911 like the proposed source. Therefore the entry may not represent BACT for the proposed source.					
Sasol Chemicals (USA) LLC	LA-0290 PSD-LA-778 (5/23/2014) (GTL unit)	Hot oil heater (process gas)	GCP, 40 CFR 63, Subpart DDDDD tuneups	1.13 lb/hr 4.13 tpy 0.0054 lb/MMBtu	171.00
	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	Fractionator feed heaters (EQT 737 & 774) (process gas)		1.37 lb/hr 4.89 tpy 0.0054 lb/MMBtu	248.70
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 1161) (process gas)	GCP, applicable provisions of 40 CFR 63, Subpart DDDDD	1.29 lb/hr 4.72 tpy 0.0054 lb/MMBtu	240.00
Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-4 (refinery fuel gas)	comply with 40 CFR 60, Subparts NNN and RRR	-	108.00
		heater 2008-5			123.00
		heater 2008-7			122.00
		heater 2008-9			122.00
		heater/reboiler 6-81	gas fuel, GCP		135.00

Notes:

1. *tpy - tons per twelve (12) consecutive months*

2. *Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.*

Step 5: Select BACT

Pursuant to 326 IAC 2-2 (PSD BACT), IDEM has established the following BACT:

BACT shall be the following:

(a) The units shall burn only natural gas and process off-gas.

(b) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(c) VOC emissions shall not exceed:

Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
EU-1007	0.0054	0.30
EU-2001	0.0054	0.69
EU-2002	0.0054	0.29
EU-2003	0.0054	0.05
EU-2004	0.0054	0.84
EU-6000	0.0054	0.37

CO

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by oxidation. CO control technologies include:

Post-combustion controls:

(a) Regenerative thermal oxidation;
(b) Catalytic oxidation;
(c) Flares

Combustion controls:

(d) Good Combustion Practices

Step 2: Eliminate Technically Infeasible Options

Carbon monoxide emissions from boilers/heaters are the result of incomplete fuel combustion. A search of the USEPA's RACT/BACT/LAER Clearinghouse indicates the use of good combustion practice and engineering design for gas-fired combustion units is the best control for CO emissions. Natural gas combustion is already efficient. It is possible to achieve CO reductions from an add-on control device;

however, any add-on oxidation control technology has been consistently shown as not cost effective since the CO concentration in these units is relatively low.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary. Good Combustion Practices are a feasible option.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Combustion Units (<100 MMBtu/hr) - CO

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-1007 Coal milling and drying heater*	*GCP*	*2.04 lb/hr 0.0365 lb/MMBtu*	*55.80*
		EU-2002 Treat gas heater		*1.93 lb/hr 0.0365 lb/MMBtu*	*52.80*
		EU-2003 Vacuum column feed heater		*0.33 lb/hr 0.0365 lb/MMBtu*	*9.00*
		EU-6000 Boiler		*2.50 lb/hr 0.0365 lb/MMBtu*	*68.50*
The source has proposed a limit of 0.0365 lb CO/MMBtu, which is more restrictive than the limits established for other sources in SIC code 2911. Therefore, this has been determined to be BACT.					
Holly Refinery & Marketing-Tulsa LLC	OK-0167 2012-1062-C(M-1)PSD (4/20/2015)	Process heaters	0.040 lb/MMBtu	-	10.00
					25.00
					42.00
					50.00
Holly Refinery & Marketing-Tulsa LLC	OK-0166 2010-599-C(M-3) (4/20/2015)	Process heater (refinery fuel gas)	0.040 lb/MMBtu	-	76.00
Sinclair Wyoming Refining Co.	WY-0071 MD-12620 (10/15/2012)	583 vacuum heater	GCP	2.60 lb/hr 0.040lb/MMBtu	64.20
		Naphtha splitter heater		1.90 lb/hr 0.040lb/MMBtu	46.30
		Hydrocracker H5 heater		1.80 lb/hr 0.040lb/MMBtu	44.90
		#1 HDS heater		1.30 lb/hr 0.040lb/MMBtu	33.40
		BSI heater		2.00 lb/hr 8.80 tpy 0.040lb/MMBtu	50.00
The BSI heater was never constructed and never tested, therefore the unit is not considered as establishing BACT.					
Conoco Phillips	OK-0136 2007-042-C PSD (2/9/2009)	NH-5 new no. 1 CTU tar stripper heater (refinery gas)	ULNB, GCP	3.92 lb/hr 17.2 tpy 0.04 lb/MMBtu	98.00
		NH-3 new no. 4 CTU vacuum heater		1.80 lb/hr 7.90 tpy 0.04 lb/MMBtu	45.00
ExxonMobil Oil Corp.	TX-0832 PSDTX768M1, PSDTX799, PSDTX802 (1/9/2018)	F-2001 Kero HDT Charge Heater and F-2002 Kero HDT Stripper Reboiler (natural gas/refinery gas)	good combustion and use of gaseous fuel	0.074 lb/MMBtu	85.50

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
		F-3001 Diesel DHDT charge heater & F-3002 diesel DHDT stripper reboiler (natural gas /refinery gas)			66.50
This RBLC entry is labeled as draft, therefore it is not considered as establishing BACT for the proposed source because the limits have not been tested.					
Indorama Ventures Olefins LLC	LA-0314 PSD-LA-813 (8/3/2016)	Dryer regenerator heater-005	GCP	0.082 lb/MMBtu	29.00
This source is in SIC code 2821, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Sasol Chemicals (USA) LLC	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	DW reactor feed heaters (EQT 738 & 775) (process gas)	GCP	2.15 lb/hr 7.25 tpy 0.035 lb/MMBtu	56.80
		Base oils DW reactor feed heater (EQT 776) (process gas)		1.24 lb/hr 3.96 tpy 0.035 lb/MMBtu	31.00
		HC reactor feed heaters (EQT 736 & 754) (process gas)		2.64 lb/hr 9.04 tpy 0.035 lb/MMBtu	70.80
		Process heater (EQT 702) (process gas)		2.74 lb/hr 9.42 tpy 0.035 lb/MMBtu	73.80
		Base oils light vacuum feed heater (EQT 777) (process gas)		2.65 lb/hr 9.09 tpy 0.035 lb/MMBtu	71.20
		Base oils heavy vacuum feed heater (EQT 778)		0.51 lb/hr 1.28 tpy 0.035 lb/MMBtu	10.00
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Reactor feed heater (EQT 1160)	GCP	0.63 lb/hr 2.30 tpy 0.035 lb/MMBtu	18.00
	LA-0298 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 772) (process gas)		1.39 lb/hr 5.06 tpy 0.035 lb/MMBtu	40.00
	LA-0302 PSD-LA-779 (5/23/2014)	Process heat boilers (EQT 1008 & 1009)		2.74 lb/hr 8.80 tpy 0.035 lb/MMBtu	78.00
The Sasol complex is in SIC code 2869, therefore these entries are not considered as establishing BACT for the proposed source, which is in SIC code 2911					
Philadelphia Energy Solutions	PA-0299 12195 (2/19/2014)	Unit 865 11H1 htr (refinery fuel gas)	GCP, annual tuneup 0.0824 lb/MMBtu	7.19 lb/hr	87.30
		Unit 865 11H2 htr		5.29 lb/hr	64.20
		Unit 866 12H1 htr		5.04 lb/hr	61.20
		Unit 868 8H101 htr		4.94 lb/hr	60.0
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-1 (natural gas and process fuel gas)	-	0.080 lb/MMBtu	36.00
		heater 94-21	gaseous fuel, GCP	-	48.00
		heater 94-29			75.00
		heater/reboiler 2004-1	gaseous fuel, GCP	0.080 lb/MMBtu	86.00
		heater/reboiler 2004-2			24.00
		heater/reboiler 2004-3			52.00
		heater/reboiler 2004-4			86.00
		heater/reboiler 2005-8			100.00
		heater/reboiler 2005-9			83.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
		heater/reboiler 2005-23			100.00
		heater/reboiler 2005-24			83.00
		CPF heater H-39-03			68.00
		CPF heater H-39-02			90.00
		DHT heater 4-81			70.00
		DHT heater 5-81			70.00
Medicine Bow Fuel & Power	WY-0066 CT-5873 (3/4/2009)	Auxiliary boiler (syngas)	GCP	5.4 lb/hr 23.80 tpy 0.080 lb/MMBtu	66.00
		HGT reactor charge heater		0.20 lb/hr 0.80 tpy 0.080 lb/MMBtu	2.22
Facility was not built and limitations were never tested, therefore this source is not considered in establishing BACT.					

Notes:

1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.*

Combustion Units (>100 MMBtu/hr) - CO

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-2001 Feed heater*	*GCP*	*4.69 lb/hr 0.0365 lb/MMBtu*	*128.40*
		EU-2004 Fractionator heater		*5.69 lb/hr 0.0365 lb/MMBtu*	*156.00*
The source has proposed a limit of 0.0365 lb CO/MMBtu, which is more restrictive than the limits established for other sources in SIC code 2911. Therefore, this has been determined to be BACT.					
Holly Refinery & Marketing-Tulsa LLC	OK-0170 2012-1062-C(M-6) (11/12/2015)	Process heater (H-205) (refinery fuel gas)	ULNB, gas fuel	0.040lb/MMBtu	100.00
	OK-0167 2012-1062-C(M-1)PSD (4/20/2015)	CDU atmospheric tower heater (refinery fuel gas)			248.00
Philadelphia Energy Solutions	PA-0299 12195 (2/19/2014)	Unit 231 B101 htr (refinery fuel gas)	GCP, annual tuneup 0.0824 lb/MMBtu	8.61 lb/hr	104.50
		Unit 210 H101 htr		15.82 lb/hr	192.00
		NH-1 new naphtha splitter reboiler		5.25 lb/hr 23.00 tpy 0.040 lb/MMBtu	131.00
		NH-4 new no. 1 CTU crude heater		5.00 lb/hr 21.90 tpy 0.040 lb/MMBtu	125.00
Sinclair Wyoming Refining Co.	WY-0071 MD-12620 (10/15/2012)	581 crude heater (refinery fuel gas)	GCP	9.30 lb/hr 0.040lb/MMBtu	233.00
Sasol Chemicals (USA) LLC	LA-0290 PSD-LA-778 (5/23/2014) (GTL unit)	Hot oil heater (EQT 623) (process gas)	GCP, NESHAP 5D	7.34 lb/hr 26.80 tpy 0.035 lb/MMBtu	171.00
	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	Fractionator feed heaters (EQT 737 & 774) (process gas)		8.86 lb/hr 31.70 tpy 0.035 lb/MMBtu	248.70

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 1161) (process gas)	GCP, NESHAP 5D	8.40 lb/hr 30.66 tpy 0.035 lb/MMBtu	240.00
The Sasol complex is in SIC code 2869, therefore these entries are not considered as establishing BACT for the proposed source, which is in SIC code 2911					
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-4 (refinery fuel gas)	gaseous fuel, GCP	0.080 lb/MMBtu	108.00
		heater 2008-5			123.00
		heater 2008-7			122.00
		heater 2008-9			122.00
		heater/reboiler 6-81			135.00
Shintech Louisiana LLC	LA-0204 PSD-LA-709(M-1) (2/27/2009)	Boilers A & B	GCP, natural gas fuel	0.036 lb/MMBtu	250.00
		Boilers C & D			
This source is in SIC code 2821, therefore this entry is not considered as establishing BACT for the proposed source, which is in SIC code 2911					

Notes:

1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.*

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 the Best Available Control Technology (PSD BACT), shall be the following:

(a) The units shall burn only natural gas and process off-gas.

(b) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(c) CO emissions shall not exceed:

Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
EU-1007	0.0365	2.04
EU-2001	0.0365	4.69
EU-2002	0.0365	1.93
EU-2003	0.0365	0.33
EU-2004	0.0365	5.69
EU-6000	0.0365	2.50

GHGs

Step 1: Identify Potential Control Technologies

(1) Energy efficiency measures
(2) Post-combustion CO_2 capture and sequestration (CCS).

Step 2: Eliminate Technically Infeasible Options

Energy efficiency measures

An opportunity for reducing GHG emissions is to increase the energy efficiency. Because CO2 emissions are a direct result of the amount of fuel fired (for a given fuel), the more efficient the process, the less fuel that is required and the less greenhouse gas emissions that result. Some energy efficiency measures that may be applied include the following:

Coal Moisture Control
The VCC process requires coal with specific properties in order to operate efficiently. Maintaining tight coal specifications to keep moisture to low levels would reduce energy requirements, and therefore reduce emissions.

General Measures
Systems to monitor and track performance of critical equipment and processes can help optimize operation. Using this information, research on machinery and equipment can be conducted, as could energy efficiency studies and other measures such as predictive maintenance. Scheduled preventive maintenance and roattion of redundant equipment helps minimize equipment downtime and optimize operation. Training programs asnd good housekeeping programs hlep decrease energy consumption.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of energy efficiency is a technically feasible option for the heaters and boiler at this source.

Post-combustion CO_2 Capture
Post-combustion CO2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO2 streams". However, the heaters and boiler at Riverview do not fit into either of these categories. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above quoted examples. However, some guidance specific to medium-sized natural gas boilers appears in its guidance document which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option.

Post-combustion CO2 capture and sequestration (CCS)
Natural gas combustion heater/boiler exhaust streams have relatively low CO2 concentrations (6-9% versus 12-15% for coal-boilers and >30% for high concentration industrial gas streams). This means that for a natural gas heater/boiler, a very large volume of gas needs to be treated to recover the CO2. Additionally, the low concentration and low pressure complicate the absorption and desorption of the CO2, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO2 capture on any natural gas combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO2 for smaller sources is more expensive due to the lack of economy-of-scale.

The CO2 must be reused or liquefied, transported and stored. Pipelines are the most common. The Co2 must be compressed to high pressures, which requires considerable energy consumption. At this time, existing infrastructure to support the transportation of CO_2 does not exist. Therefore, transportation of the CO_2 stream would require the construction of a pipeline to the nearest sequestration site.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of post-combustion CO_2 capture is not a technically or economically feasible option for the operations at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Combustion Units - CO_2e

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-1007 Coal milling and drying heater*	*energy efficiency, good combustion practices, and gaseous fuel*	*29,127 tons/yr*	*55.80*
		EU-2001 Feed heater		*67,023 tons/yr*	*128.40*
		EU-2002 Treat gas heater		*27,561 tons/yr*	*52.80*
		EU-2003 Vacuum column feed heater		*4,698 tons/yr*	*9.00*
		EU-2004 Fractionator heater		*81,430 tons/yr*	*156.00*
		EU-6000 Boiler		*35,756 tons/yr*	*68.50*
Production-based limits, e.g., lb/MMBtu or lb/1000 lb steams, cannot be considered as establishing BACT for the proposed source because of differences in fuel heating values and unit efficiencies, and because not all units are steam-generating equipment.					
Exxon Mobil Oil Corp.	TX-0832 PSDTX768M1, PSDTX799, PSDTX802 (1/9/2018)	F-2001 kero HDT charge heater & F-2002 kero HDT stripper reboilers	stack temp 600°F, GCP[3]	-	85.50
		F-3001 diesel DHDT charge heater and F-3002 diesel DHDT stripper reboiler			66.50
This RBLC entry is labeled as draft, therefore it is not considered as establishing BACT for the proposed source because the limits have not been tested.					
Indorama Ventures Olefins LLC	LA-0314 PSD-LA-813 (8/3/2016)	Dryer regenerator heater-005	gas fuel, GCP	-	29.00
Holly Refinery & Marketing-Tulsa LLC	OK-0167 2012-1062-C(M-1)PSD (4/20/2015)	Process heaters	gas fuel, energy efficiency	146 lb/MMBtu	10.00
					25.00
					42.00
					50.00
		CDU atmospheric tower heater (refinery fuel gas)			248.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
	OK-0166 2010-599-C(M-3) (4/20/2015)	Process heater (refinery fuel gas)			76.00
	OK-0143 98-014-C(M-19) (3/1/2012)	Natural gas & refinery gas-fired boiler	economizer, microprocessor controls	206 lb CO2e/1000 lb steam (30 day avg)	214.60
Sasol Chemicals (USA) LLC	LA-0290 PSD-LA-778 (5/23/2014) (GTL unit)	Hot oil heater (process gas)	natural gas fuel, GCP	89564 tpy	171.00
	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	DW reactor feed heaters (EQT 738 & 775) (process gas)		34317 tpy (738) 35302 tpy (775)	56.80
		Base oils DW reactor feed heater (EQT 776) (process gas)		22757 tpy	31.00
		HC reactor feed heaters (EQT 736 & 754) (process gas)		43002 tpy (736) 44252 tpy (754)	70.80
		Process heater (EQT 702) (process gas)		61709 tpy	73.80
		Base oils light vacuum feed heater (EQT 777) (process gas)		54353 tpy	71.20
		Base oils heavy vacuum feed heater (EQT 778)		6235 tpy	10.00
		Fractionator feed heaters (EQT 737 & 774) (process gas)		153286 tpy (737) 157892 tpy (774)	248.70
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Reactor feed heater (EQT 1160)	GCP	9484 tpy	18.00
		Hot oil heater (EQT 1161) (process gas)		143933 tpy	240.00
	LA-0298 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 772) (process gas)		16692 tpy	40.00
	LA-0302 PSD-LA-779 (5/23/2014)	Process heat boilers (EQT 1008 & 1009)		69173 tpy (comb)	78.00
The Sasol complex is in SIC code 2869, therefore these entries are not considered as establishing BACT for the proposed source, which is in SIC code 2911					
Lima Refining Co.	OH-0362 P0114527 (12/23/2013)	Vacuum unit II heater	low carbon gaseous fuel, GCP[4]	-	102.30

Notes:

1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.*
3. *TX-0832 GCP: performing preventative maintenance as necessary, and inspecting and tuning burners and conducting a visual inspection of the heater components annually.*

4. *OH-362 GCP: Heat recovery through use of a convection section and boiler feed water preheating; and excess oxygen monitoring and annual burner tuning and heater inspection.*

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 the Best Available Control Technology (PSD BACT), shall be the following:

(a) The units shall burn only natural gas and process off-gas.

(b) The units shall be designed and operated to achieve the highest practical energy efficiency.

(c) The units shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(d) CO_2e emissions shall not exceed the value of tons per twelve (12) consecutive month period shown in the table below:

Emission Limitations	
Unit ID	**CO_2e Limit**
EU-1007	29,127
EU-2001	67,023
EU-2002	27,561
EU-2003	4,698
EU-2004	81,430
EU-6000	35,756

BACT Analysis
Sulfur Recovery/Tail Gas Treatment Unit (TGTU)

Step 1: Identify Potential Control Technologies

The sulfur recovery process converts H_2S (from the amine regeneration process and sour water stripping process) to elemental sulfur. In this case, the Claus process is used. Feed gases are burned with sufficient air to combust some of the H_2S to promote the Claus reactions. This process creates emissions.

NOx emissions can be controlled with the following control technologies:

(1) Low NOx Burner (LNB)/Ultra low-Nox burner (ULNB)

Low NOx Burners (LNB)
Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible.

Step 2: Eliminate Technically Infeasible Options

Low Nox burners are technically feasible.
Thermal oxidizers are not economically feasible for this sulfur recovery unit.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Low Nox burners are technically feasible.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - PM/PM$_{10}$/PM$_{2.5}$

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Riverview Energy	*Proposed*	*Claus SRU TGTU (EU-3001 and EU-3002)*	*SRU Tail gas unit with incinerator burner and low-NOx burners* *Good Combustion Practices*	*PM (filterable):* *0.0019 lb/MMBtu* *0.10 lb/hr, each* *PM10/PM2.5:* *0.0074 lb/MMBtu* *0.39 lb/hr (each)* *10% opacity*	*111 (max, ea)* *159 (comb, bottle-necked)*
BP Products, North America	OH-0357 P0111667 (9/20/2013)	Claus SRU	None	PM10: 0.6 lb/hr 1.74 tpy based on AP-42, 7.6 lb/MMscf (equivalent to 0.0074 lb/MMBtu)	120 (32.15 MMBtu/hr)
This is the most stringent limit for PM10. Therefore, it has been determined to be BACT for PM10 and PM2.5.					
Sunoco	OH-0308 04-01447 (2/23/2009)	Sulfur Recovery Unit (new)	Tail gas treatment units and SRU incinerator thermal oxidizer low-nox burners	PM10: 1.36 lb/hr and 5.96 tpy (12-month rolling avg.) and 0.08 lb/MMBtu 10% opacity (6-min avg.)	17 MMBtu/hr
This is the most stringent limit for opacity, therefore it has been included in BACT.					
Conoco Phillips Co.	MT-0030 2619-24 (11/19/2008)	Claus SRU TGTU	Proper equipment design, good combustion practices and use gaseous fuels	PM/PM10/PM2.5: none	235
This is the most stringent limitation on design and operating practice, therefore it has been included in BACT.					
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Sulfur Recovery Plant	ATS units	PM: 3.67 lb/hr PM10: 7.76 lb/hr	-
Not considered a representative comparison. PM/PM10 emissions from the sulfur recovery plant at this cource are controlled by a mist eliminator, indicating that the ATS process is fundamentally different from the Claus sulfur recovery process with tail gas treatment. Permit cited does not appear to be available on line.					
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Sulfur recovery process units	thermal oxidizer low NOx burners	VE: 20% Opacity PM10: 0.2 lb/hr (0.85 tpy) (AP-42)	23.5 ton/hr
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					

Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - SO$_2$

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Riverview Energy	*Proposed*	*Claus SRU TGTU (EU-3001 and EU-3002)*	*SRU Tail gas unit with incinerator burner and low-NOx burners Good Combustion Practices*	*150 ppmv @ 0% O_2 (annual) 167 ppmv @ 0% O_2 (12-hour avg) 26.30 lb/hr (ea)*	*111 (max, ea) 159 (comb, bottle-necked)*
Conoco Phillips Co.	MT-0030 2619-24 (11/19/2008)	Claus SRU TGTU	TGTUf	150 ppmv @ 0% O_2 (annual) 167 ppmv @ 0% O_2 (12-hour avg)	235
This is the most stringent limit for SO_2 - considered more restrictive than higher ppmv limits with specified control efficiencies. Therefore, this has been determined to be BACT.					
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Sulfur Recovery Plant	ATS units	90 ppmvd @ 0% O_2 (24 hr avg) SO_2 CEMS	-
Not considered a representative comparison. PM/PM10 emissions from the sulfur recovery plant at this cource are controlled by a mist eliminator, indicating that the ATS process is fundamentally different from the Claus sulfur recovery process with tail gas treatment. Permit cited does not appear to be available on line.					
Diamond Shamrock Refining	TX-0720 PSDTX861M3 (12/20/2013)	Sulfur Recovery Unit (SRU)	SCOT technology and tail gas incinerators	99.8% sulfur recovery	Not listed
BP Products, North America	OH-0357 P0111667 (9/20/2013)	Claus SRU	None	250 ppmv 75 tpy (combined all 3)	120 (32.15 MMBtu/hr)
DCP Midstream	TX-0604 676A, PSDTX1246 (11/3/2011)	Tail gas incinerator	-	1521.8 tpy	
Valero Refining	TX-0595 2937, PSDTX1023M2 (8/19/2010)	Sulfur Recovery Unit (SRU)	none	267 lb/hr 19.2 tpy	
Valero Refining	TX-0592 38754, PSDTX324M13 (3/29/2010)	Sulfur Recovery Unit (SRU)	none	761 lb/hr 9.1 tpy	
Valero Energy Corp.	DE-0020 AQM-003/00016 (2/26/2010)	Sulfur Recovery Unit (SRU)	tail gas unit with stack incinerator	250 ppmv @ 2% O2 (12-hr rolling avg.) 122.0 lb/hr (24-hr rolling avg.) 99.99% control	822
Sunoco	OH-0308 04-01447 (2/23/2009)	Sulfur Recovery Unit (existing)	Tail gas treatment units and SRU incinerator for H_2S	0.07 lb/lb sulfur processed 250 ppmv @ 0% excess air (12-hr rolling avg.) SO_2 CEMS (NSPS Subpart J)	
		Sulfur Recovery Unit (new)	Tail gas treatment units and SRU incinerator thermal oxidizer low-nox burners	9.88 lb/hr 43.28 tpy 250 ppmv @ 0% excess air (12-hr rolling avg.) SO2 CEMS	17 MMBtu/hr
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Sulfur recovery process units	thermal oxidizer low NOx burners	4893.415 lb/hr 142.72 tpy 250 ppmv (subpart Ja)	23.5 ton/hr
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Sunoco	PA-0256 06144 (1/29/2008)	Sulfur Recovery Unit	Tail gas combustion unit	250 ppm 31.72 lb/hr	
Navajo Refining	NM-0050 PSD-NM-195-M25 (12/14/2007)	Sulfur Recovery Unit	Tail gas incinerator	192 ppmv @ 0% O2 (12-hr rolling avg. and 365 day rolling avg.)	
Texstar	TX-0501 6051, PSD-TX-55M3 (7/11/2006)	Tail gas incinerator stack	-	350.0 lb/hr 1095.0 tpy	

Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - NOx

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Riverview Energy	*Proposed*	*Claus SRU TGTU (EU-3001 and EU-3002)*	*SRU Tail gas unit with incinerator burner and low-NOx burners* *Good Combustion Practices*	*0.1 lb/MMBtu* *5.28 lb/hr, each*	*111 (max, ea)* *159 (comb, bottle-necked)*
BP Products, North America	OH-0357 P0111667 (9/20/2013)	Claus SRU	Low Nox burners	4.4 lb/hr 12.76 tpy (0.1 lb/MMBtu)	120 (32.15 MMBtu/hr)
This is the most stringent limit for NOx. Therefore, this has been determined to be BACT.					
Sunoco	OH-0308 04-01447 (2/23/2009)	Sulfur Recovery Unit (new)	Tail gas treatment units and SRU incinerator thermal oxidizer low-nox burners	2.55 lb/hr 11.17 tpy (12-month rolling avg.) 0.15 lb/MMBtu	17 MMBtu/hr
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Sulfur recovery process units	thermal oxidizer low NOx burners	1224 lb/hr 7.35 tpy	23.5 ton/hr
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Conoco Phillips Co.	MT-0030 2619-24 (11/19/2008)	Claus SRU TGTU	Thermal Oxidizer with low NOx burner	none	235
Texstar	TX-0501 6051, PSD-TX-55M3 (7/11/2006)	Tail gas incinerator stack	-	8.46 lb/hr 37.05 tpy	

Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - VOC

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Riverview Energy	*Proposed*	*Claus SRU TGTU (EU-3001 and EU-3002)*	*SRU Tail gas unit with incinerator burner and low-NOx burners* *Good Combustion Practices*	*0.0054 lb/MMBtu* *0.28 lb/hr, each*	*111 (max, ea)* *159 (comb, bottle-necked)*

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
The source has proposed limiting VOC to 0.0054 lb/MMBtu, which is more restrictive than other sources found in the RBLC. Therefore this has been determined to be BACT for the proposed source.					
Sunoco	OH-0308 04-01447 (2/23/2009)	Sulfur Recovery Unit (new)	Tail gas treatment units and SRU incinerator thermal oxidizer low-nox burners	0.89 lb/hr 3.89 tpy (12-month rolling avg.) (equivalent to 0.052 lb/MMBtu) 60 ppmvd @ 0% O2	17 MMBtu/hr
BP Products, North America	OH-0357 P0111667 (9/20/2013)	Claus SRU	None	6.2 tpy each (equivalent to 0.04 lb/MMBtu)	120 (32.15 MMBtu/hr)
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Sulfur recovery process units	thermal oxidizer low NOx burners	0.2 lb/hr (0.85 tpy) (AP-42)	23.5 ton/hr
Note: Source was not constructed and it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Conoco Phillips	IL-0103 06050052 (8/5/2008)	Sulfur Recovery Units E and F	Good combustion practices for thermal oxidizers on tail gas treating unit	VOC: 0.005 lb/MMBtu (3-hr avg.)	
This RBLC entry is identified as LAER, therefore it is not considered as establishing BACT for the proposed source.					

Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - CO

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Riverview Energy	*Proposed*	*Claus SRU TGTU (EU-3001 and EU-3002)*	*SRU Tail gas unit with incinerator burner and low-NOx burners* *Good Combustion Practices*	*0.082 lb/MMBtu* *4.33 lb/hr, each* *65 ppmvd @ 0% O2* *(30-day rolling avg.)* *CO CEMS*	*111* *(max, ea)* *159* *(comb, bottle-necked)*
BP Products, North America	OH-0357 P0111667 (9/20/2013)	Claus SRU	None	2.7 lb/hr each 8.07 tpy 84 lb/MMscf (equivalent to 0.082 lb/MMBtu)	120 (32.15 MMBtu/hr)
Chevron Products	MS-0089 1280-00058 (4/14/2009)	Tail Gas Treating Units for SRU IV, V, and VI	Two low-Nox thermal oxidizers	22.75 lb/hr (3-hr rolling avg.), 99.7 tpy (12-month rolling avg.) 65 ppmvd @ 0% O2 (30-day rolling avg.) CO CEMS	1,220
Conoco Phillips	IL-0103 06050052 (8/5/2008)	Sulfur Recovery Units E and F	Good combustion practices for thermal oxidizers on tail gas treating unit	0.082 lb/MMBtu	
These are the most stringent limits for CO. Therefore, these have been determined to be BACT.					
Chevron Products	MS-0089 1280-00058 (4/14/2009)	Sulfur Recovery Units II and III	Two low-NOx thermal oxidizers	16.92 lb/hr (3-hr rolling avg.) 49.42 tpy (12-month rolling avg.) 100 ppmvd @ 0% O2 (30-day rolling avg.) CO CEMS	290

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Sunoco	OH-0308 04-01447 (2/23/2009)	Sulfur Recovery Unit (new)	Tail gas treatment units and SRU incinerator thermal oxidizer low-nox burners	2.59 lb/hr 11.34 tpy (12-month rolling avg.) 0.15 lb/MMBtu incinerator	17 MMBtu/hr
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Sulfur recovery process units	thermal oxidizer low NOx burners	52.5 lb/hr (incineration of tail gas, each unit) 0.32 tpy 3 startup/shutdown events per year for each unit	23.5 ton/hr
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Texstar	TX-0501 6051, PSD-TX-55M3 (7/11/2006)	Tail gas incinerator stack	-	3.69 lb/hr 15.9 tpy	
The source is a natural gas liquids facility in SIC code 132 (also provides NAICS code of 221210), therefore this entry should not be considered as establishing BACT for the proposed source.					

Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - CO_2e

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Riverview Energy	*Proposed*	*Claus SRU TGTU (EU-3001 and EU-3002)*	*SRU Tail gas unit with incinerator burner and low-NOx burners* *Good Combustion Practices*	*40,872 tpy (combined)*	*111 (max, ea)* *159 (comb, bottle-necked)*
BACT proposed by the source. Tons per year limits at other sources are not considered applicable because unit capacities are not available for comparison.					
Dakota Prairie Refining	ND-0031 PTC12090 (2/21/2013)	Sulfur recovery unit	none	1137 tpy	

Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - H_2SO_4 mist

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Riverview Energy	*Proposed*	*Claus SRU TGTU (EU-3001 and EU-3002)*	*SRU Tail gas unit with incinerator burner and low-NOx burners* *Good Combustion Practices*	*H_2SO_4: 0.0244 lb/MMBtu and 1.29 lb/hr, each (equivalent to 0.28 lb/long ton S)*	111 (max, ea) 159 (comb, bottle-necked)
Limits proposed by the source for sulfuric acid mist are more restictive than any found in RBLC, therefore these are selected as BACT.					
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Sulfur recovery process units	thermal oxidizer low NOx burners	H_2SO_4: 2.37 lb/hr (10.4 tpy) (equivalent to 0.10 lb/long ton)	23.5 ton/hr
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					

Step 5: Select BACT

IDEM, OAQ has established BACT for TGTUA and TGTUB as:

(a) PM (filterable) emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0019 lb/MMBtu and 0.10 lb/hr, each.

(b) PM_{10} emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0074 lb/MMBtu and 0.39 lb/hr, each.

(c) $PM_{2.5}$ emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0074 lb/MMBtu and 0.39 lb/hr, each.

(d) The SO_2 emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 150 ppmv @ 0% excess air (on a twelve month rolling average) and shall be less than 167 ppmv @ 0% excess air (on a twelve hour average).

(e) The SO_2 emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 26.30 lb/hr, each.

(f) The tail gas treatment units (TGTUA and TGTUB) shall each use low-NOx burners.

(g) NOx emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.10 lb/MMBtu and 5.28 lb/hr, each.

(h) VOC emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0054 lb/MMBtu and 0.28 lb/hr, each.

(i) CO emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 65 ppmv @ 0% O_2, shall not exceed 0.082 lb/MMBtu and 4.33 lb/hr, each.

(j) Sulfuric Acid Mist (H_2SO_4 mist) emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0244 lb/MMBtu and 1.29 lb/hr, each.

(k) Opacity shall not exceed ten percent (10%) on a six-minute average.

(l) Incinerators (A-605A and A-605B) shall use good combustion practices. Good combustion practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

(m) Carbon dioxide equivalent (CO_2e) emissions, as defined at 40 CFR 98.6, from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 40,872 tons per twelve (12) consecutive month period, combined, with compliance determined at the end of each month.

BACT Analysis
Flares

Step 1: Identify Potential Control Technologies

The following control technologies have been identified to control emissions from the flare:

(1) Flare design and good combustion practices;
(2) Process flaring minimization practices; and

(3) Flare Gas Recovery.

Add-on controls typically have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

Flare design and good combustion practices
Flare design, good combustion practices and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option.

Process flaring minimization practices
To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of CO will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

The use of process flaring minimization practices is a technically feasible control option.

Flare Gas Recovery
Flare gas recovery is not a feasible option. These flares do not operate constantly; only the pilot flame does. There would not be anything to recover except in the rare case of a process upset – which would preclude the use of any heat recovered.

Flare - PM/PM_{10}/$PM_{2.5}$

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Riverview Energy	*Proposed*	*Loading flare*	*Operate in accordance with 40 CFR 60.18 Implement a Flare Management Plan as required by 40 CFR 60, Subpart Ja*	*sweep & pilot operation: use gaseous fuel PM (filterable): 0.0019 lb/MMBtu SB: 1.62E-03 lb/hr LP: 0.014 lb/hr HP: 0.014 lb/hr loading: 4.22E-04 lb/hr PM10/PM2.5: 0.0074 lb/MMBtu SB: 6.32E-03 lb/hr LP: 0.053 lb/hr HP: 0.053 lb/hr loading: 1.64E-03 lb/hr Flare stream operations: VE: 0% except for 5 min during 2 cons. hrs*	*0.20*
		Sulfur block flare			*0.77*
		Low Pressure flare			*6.50*
		High pressure flare			*6.50*
Agrium U.S. Inc.	AK-0083 AQ0083CPT 06 (1/6/2015)	1.25 MMBtu/hr Ammonia Tank Flare, 0.4 MMBtu/hr Emergency Flare, and 1.25 MMBtu/hr Small Flare	Work Practice Requirements and Limited Use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events)	PM/PM10/PM2.5: 0.0074 lb/MMBtu	
0.0074 lb/MMBtu is most stringent for PM10/PM2.5. Therefore this is determined to be BACT					
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-	Startup/Shutdown Flares	None	0.0076 lb/MMBtu 0% VE (6-min avg.)	-
		Biomethanator Flare	None	PM/PM10: 0.0019	6.4

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
	982P (8/8/2007)			lb/MMBtu 0% VE (6-min avg.)	
0.0019 lb/MMBtu is most stringent for PM (filterable). Therefore this is determined to be BACT					
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hydrogen Plant feed gas - flare	flare	Comply with 40 CFR 60.18 VE: 0% except for 5 min during 2 cons. hrs	2472
Exxonmobil	TX-0796 6860, PSDTX1464 (4/20/2016)	HP Flare	None	None	
Exxonmobil	TX-0795 83702, PSDTX843M1, PSDTX860M1 (4/18/2016)	Flares	None	None	
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Main flare and Alky flare	None	Meet requirements of 40 CFR 60.18 and API Recommended Practices 520 and 521	-
Liberty Landfill	IN-0246 T181-33869-00035 (10/22/2015)	Landfill gas Flare	Good Combustion Practices	17 lb/MMcf, CH4 (converted to 0.017 lb/MMBtu)	
Golden Pass Terminal	TX-0766 116055, PSDTX1386, GHGPSDTX100 (9/11/2015)	Flares	None	None	
Citgo Refining and Chemicals	TX-0478 PSD-TX-408M3 (4/20/2015)	Acid gas flare	None	None	-
BASF	TX-0728 118239, N200 (4/1/2015)	Flares	None	None	
Corpus Christi Liquefaction	TX-0679 GHGPSDTX123 (2/27/2015)	Flares	None	None	
ExxonMobil Corporation	AK-0082 AQ1201CPT03 (1/23/2015)	50 MMscf/yr Drilling Flare, 35 MMscf/yr HP Flare-Pilot/Purge, 20 MMscf/yr LP Flare-Pilot/Purge	None	0.0264 lb/MMBtu	-
Norco Hydrogen	LA-0264 PSD-LA-750(M1) (9/4/2012)	Natural gas flare	Maintain minimum heat content of the flare gas at 200 btu/scf to ensure the flame at the flare tips at all the times.	0.01 lb/hr	0.31
Indiana Gasification	IN-0166 T147-30464-00060 (6/27/2012)	Syngas hydrocarbon flare	Flare minimization plan	PM/PM10: 3.21 lb/hr PM2.5: 3.01 lb/hr	0.27
		Acid Gas flare		None	0.27
This source was never constructed and the permit was revoked. Therefore the reference is not considered in determining BACT.					
Sabina Petrochemicals	TX-0575 41945,	High and low pressure flares	None	None	1600 tpy

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
	N018M1 (8/20/2010)				
Lake Charles Cogeneration, LLC	LA-0231 PSD-LA-742 (6/22/2009)	acid gas flare	Good design and monitoring to ensure the presence of a flame at the flare tip at all the time	PM10: 0.01 lb/hr max	0.27 MMBtu/hr
This source is in SIC code 2865, therefore this entry is not considered as establishing BACT for the proposed source, which is in SIC code 2911					
Navajo Refining Co.	NM-0050 PSD-NM-195-M25 (12/14/2007)	Natural gas and hydrogen flare	None	None	7.5
Rohm and Haas Texas Inc.	TX-0487 PSD-TX-828M1 (3/24/2005)	Feed and exit gas flare	None	None	-

Flare - SO_2

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Riverview Energy	*Proposed*	*Loading flare*	*Operate in accordance with 40 CFR 60.18. Implement a Flare Management Plan as required by 40 CFR 60, Subpart Ja*	*Burn only natural gas or process off-gas in sweep or pilot mode. Limits during sweep or pilot operation:* *HP: 0.013 lb/hr* *LP: 0.013 lb/hr* *SB: 0.069 lb/hr* *Loading: 0.069*	*0.20*
		Sulfur block flare			*0.77*
		Low Pressure flare			*6.50*
		High pressure flare			*6.50*
Requirements of 40 CFR 60 103a(h) are considered BACT for sweep & pilot operations burning refinery fuel gas.					
Exxonmobil	TX-0796 6860, PSDTX1464 (4/20/2016)	HP Flare	None	None	
Exxonmobil	TX-0795 83702, PSDTX843M1, PSDTX860M1 (4/18/2016)	Flares	None	None	
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Main flare and Alky flare	None	Meet requirements of 40 CFR 60.18 and API Recommended Practices 520 and 521	-
Liberty Landfill	IN-0246 T181-33869-00035 (10/22/2015)	Landfill gas Flare	None	None	
Golden Pass Terminal	TX-0766 116055, PSDTX1386, GHGPSDTX100 (9/11/2015)	Flares	None	None	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Citgo Refining and Chemicals	TX-0766 116055, PSDTX1386, GHGPSDTX 100 (9/11/2015)	Acid gas flare	None	None	-
BASF	TX-0478 PSD-TX-408M3 (4/20/2015)	Flares	None	SO_2: 1.02 lb/hr	
Corpus Christi Liquefaction	TX-0728 118239, N200 (4/1/2015)	Flares	None	None	
ExxonMobil Corporation	AK-0082 AQ1201CPT 03 (1/23/2015)	50 MMscf/yr Drilling Flare, 35 MMscf/yr HP Flare-Pilot/Purge, 20 MMscf/yr LP Flare-Pilot/Purge	None	None	-
Agrium U.S. Inc.	AK-0083 AQ0083CPT 06 (1/6/2015)	1.25 MMBtu/hr Ammonia Tank Flare, 0.4 MMBtu/hr Emergency Flare, and 1.25 MMBtu/hr Small Flare	None	None	
Norco Hydrogen	LA-0264 PSD-LA-750(M1) (9/4/2012)	Natural gas flare	None	None	0.31
Indiana Gasification - IN	IN-0166 / T147-30464-00060 (6/27/2012)	Syngas hydrocarbon flare	None	Flare minimization plan	0.27
		Acid Gas flare	None		0.27
This source was never constructed and the permit was revoked. Therefore the reference is not considered in determining BACT.					
Sabina Petrochemicals	TX-0575 41945, N018M1 (8/20/2010)	High and low pressure flares	None	None	1600 tpy
Lake Charles Cogeneration, LLC	LA-0231 PSD-LA-742 (6/22/2009)	acid gas flare	no additional control	SO_2: 0.01 lb/hr max	0.27
Navajo Refining Co.	NM-0050 PSD-NM-195-M25 (12/14/2007)	Natural gas and hydrogen flare	None	SO_2: 0.1 lb/hr 0.4 tpy	7.5
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Startup/Shutdown Flares	None	SO_2: 0.395 lb/MMBtu	-
		Biomethanator Flare	None	SO_2: 0.0007 lb/MMBtu	6.4
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hydrogen Plant feed gas - flare	flare	Comply with 40 CFR 60.18 SO_2: 0.01 lb/hr	2472
Rohm and Haas Texas Inc.	TX-0487 PSD-TX-828M1 (3/24/2005)	Feed and exit gas flare	None	SO_2: 0.11 lb/hr 0.01 tpy	-

Flare - NOx

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Riverview Energy	*Proposed*	*Loading flare*	*Operate in accordance with 40 CFR 60.18. Implement a Flare Management Plan as required by 40 CFR 60, Subpart Ja*	*sweep & pilot operation: use gaseous fuel NOx: 0.099 lb/MMBtu SB: 8.46E-02 lb/hr LP: 0.71 lb/hr HP: 0.71 lb/hr loading: 2.20E-02 lb/hr Flare stream operations: NOx: 0.068 lb/MMBtu*	*0.20*
		Sulfur block flare			*0.77/0.85 (LHV/HHV)*
		Low Pressure flare			*6.50/7.22*
		High pressure flare			*6.50/7.22*
Liberty Landfill	IN-0246 T181-33869-00035 (10/22/2015)	Landfill gas Flare	Good Combustion Practices	NOx: 0.068 lb/MMBtu	
ExxonMobil Corporation	AK-0082 AQ1201CPT03 (1/23/2015)	50 MMscf/yr Drilling Flare, 35 MMscf/yr HP Flare-Pilot/Purge, 20 MMscf/yr LP Flare-Pilot/Purge	None	NOx: 0.068 lb/MMBtu	-
Agrium U.S. Inc.	AK-0083 AQ0083CPT06 (1/6/2015)	1.25 MMBtu/hr Ammonia Tank Flare, 0.4 MMBtu/hr Emergency Flare, and 1.25 MMBtu/hr Small Flare	Work Practice Requirements and Limited Use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events)	NOx: 0.068 lb/MMBtu	
0.068 lb NOx/MMBtu, considered as while actively flaring because that is how the emission factor is defined in AP-42, Chapter 13.5 is most stringent for NOx. Therefore this is BACT					
Exxonmobil	TX-0796 6860, PSDTX1464 (4/20/2016)	HP Flare	None	None	
Exxonmobil	TX-0795 83702, PSDTX843M1, PSDTX860M1 (4/18/2016)	Flares	None	None	
Golden Pass Terminal	TX-0766 116055, PSDTX1386, GHGPSDTX100 (9/11/2015)	Flares	None	None	
Citgo Refining and Chemicals	TX-0478 PSD-TX-408M3 (4/20/2015)	Acid gas flare	None	None	-
BASF	TX-0728 118239, N200 (4/1/2015)	Flares	None	NOx: 223.41 lb/hr (5.39 tpy)	
Corpus Christi Liquefaction	TX-0679 GHGPSDTX123 (2/27/2015)	Flares	None	None	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Norco Hydrogen	LA-0264 PSD-LA-750(M1) (9/4/2012)	Natural gas flare	Proper Equipment designs and good combustion practices	NOx: 0.03 lb/hr (0.09 ton/yr) (calculated 0.097 lb/MMBtu)	0.31
Indiana Gasification - IN	IN-0166 T147-30464-00060 (6/27/2012)	Syngas hydrocarbon flare	Flare minimization plan	NOx: 43.09 lb/hr (calculated 160 lb/MMBtu)	0.27
Sabina Petrochemicals	TX-0575 41945, N018M1 (8/20/2010)	High and low pressure flares	None	9.07 tpy	1600 tpy
Lake Charles Cogeneration, LLC	LA-0231 PSD-LA-742 (6/22/2009)	acid gas flare	no additional control	NOx: 0.05 lb/hr max	0.27 MMBtu/hr
Navajo Refining Co.	NM-0050 PSD-NM-195-M25 (12/14/2007)	Natural gas and hydrogen flare	None	NOx: 0.54 lb/hr 2.38 tpy (calculated 0.072 lb/MMBtu)	7.5
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Startup/Shutdown Flares	None	NOx: 0.2 lb/MMBtu	-
		Biomethanator Flare	None	NOx: 0.07 lb/MMBtu	6.4
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hydrogen Plant feed gas - flare	flare	Comply with 40 CFR 60.18 NOx: 1.8 lb/hr	2472
Rohm and Haas Texas Inc.	TX-0487 PSD-TX-828M1 (3/24/2005)	Feed and exit gas flare	None	NOx: 130.65 lb/hr 7.78 tpy (0.0641 lb NOx/MMBtu)	-

Flare - VOC

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Riverview Energy	*Proposed*	*Loading flare (controlling the Naphtha loading operation and diesel loading operation)*	*Operate in accordance with 40 CFR 60.18. Implement a Flare Management Plan as required by 40 CFR 60, Subpart Ja*	*sweep & pilot operation:* *use gaseous fuel* *VOC: 0.0054 lb/MMBtu* *1.20E-03 lb/hr* *Flare stream operations:* *98% DRE* *Submerged loading* *when loading naphtha: 0.0082 lb/kgal* *when loading diesel: 0.014 lb/kgal*	*0.20*
		Sulfur block flare		*sweep & pilot operation:* *use gaseous fuel* *VOC: 0.0054 lb/MMBtu*	*0.77*
		Hydrogen plant flare			*6.50*

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
		High pressure flare		*SB: 4.62E-03 lb/hr* *LP: 0.039 lb/hr* *HP: 0.039 lb/hr* *Flare stream operations: 98% DRE*	*6.50*
Agrium U.S. Inc.	AK-0083 AQ0083CPT06 (1/6/2015)	1.25 MMBtu/hr Ammonia Tank Flare, 0.4 MMBtu/hr Emergency Flare, and 1.25 MMBtu/hr Small Flare	Work Practice Requirements and Limited Use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events)	0.0054 lb/MMBtu	
Midwest Fertilizer	IN-0173 T129-33576-00059 (6/4/2014)	Flare	NG pilot, flare minimization practices	0.0054 lb/MMBtu 47.26 lb/hr	
0.0054 lb/MMbtu is most stringent for VOC under pilot operating conditions. Therefore this is BACT.					
M&G Resins	TX-0671 108446, PSDTX1352 (12/1/2014)	Flare	None	40 CFR 60.18 0.01 lb/hr 99% DRE for compounds up to 3 carbons, 98% others	
Lone Star NGL Fractionators	TX-0723 N182 (11/21/2014)	Flare	Meet 60.18 for continuous flame or pilot monitoring, smokeless design, sufficient heat content in the waste gas, and limited tip velocity.	98% CE	
Dow Chemical	TX-0697 107153, PSDTX1328 (3/27/2014)	LP Flare	flare will meet NSPS 60.18 standards for continuous pilot flame, waste gas heat content and tip velocity	99% DRE for compounds up to C3 carbons, 98% others	
Dow Chemical	TX-0721 100787, PSDTX1314 (1/7/2013)	Flare	good combustion	5.5 lb/MMscf 99% DRE for compounds up to C3 carbons, 98% others	
Sabina Petrochemicals	TX-0575 41945, N018M1 (8/20/2010)	High and low pressure flares	None	0.32 tpy 98% CE	1600 tpy
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Biomethanator Flare	None	0.052 lb/MMBtu 98% CE	6.4
Exxonmobil	TX-0796 6860, PSDTX1464 (4/20/2016)	HP Flare	None	None	
Exxonmobil	TX-0795 83702, PSDTX843M1, PSDTX860M1 (4/18/2016)	Flares	None	None	
Liberty Landfill	IN-0246 T181-33869-00035 (10/22/2015)	Landfill gas Flare	None	None	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Golden Pass Terminal	TX-0766 116055, PSDTX1386, GHGPSDTX 100 (9/11/2015)	Flares	None	None	
BASF	TX-0728 118239, N200 (4/1/2015)	Flares	None	9.32 lb/hr	
Corpus Christi Liquefaction	TX-0679 GHGPSDTX 123 (2/27/2015)	Flares	None	None	
ExxonMobil Corporation	AK-0082 AQ1201CPT 03 (1/23/2015)	50 MMscf/yr Drilling Flare, 35 MMscf/yr HP Flare-Pilot/Purge, 20 MMscf/yr LP Flare-Pilot/Purge	None	0.14 lb/MMBtu	-
Anadarko Petroleum	FL-0347 OCS-EPA-R4015 (9/16/2014)	Boom Flare	Good combustion practices and proper flare maintenance	None	
Norco Hydrogen	LA-0264 PSD-LA-750(M1) (9/4/2012)	Natural gas flare	None	None	0.31
Indiana Gasification - IN	IN-0166 T147-30464-00060 (6/27/2012)	Syngas hydrocarbon flare	None	None	0.27
		Acid Gas flare	None	Flare minimization plan	0.27
This source was never constructed and the permit was revoked. Therefore the reference is not considered in determining BACT.					
WTG Benedum	TX-0605 8941, PSDTX487M 1 (12/21/2011)	Acid gas flare	None	None	-
Navajo Refining Co.	NM-0050 PSD-NM-195-M25 (12/14/2007)	Natural gas and hydrogen flare	None	0.03 lb/hr 0.14 tpy (calculated 0.004 lb/MMBtu)	7.5
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Startup/Shutdown Flares	None	0.006 lb/MMBtu	-
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hydrogen Plant feed gas - flare	flare	Comply with 40 CFR 60.18 VOC: 0.01 lb/hr	2472
Rohm and Haas Texas Inc.	TX-0487 PSD-TX-828M1 (3/24/2005)	Feed and exit gas flare	None	0.22 lb/hr 0.09 tpy	-

IDEM is aware that that the above control technologies may be able to periodically achieve control efficiencies that exceed 98% under certain operating conditions. However, BACT must be achievable on a consistent basis under normal operational conditions. BACT limitations do not necessarily reflect the highest possible control efficiency achievable by the technology on which the emission limitation is based. The permitting authority has the discretion to base the emission limitation on a control efficiency that is somewhat lower than the optimal level. There are several reasons why the permitting authority might choose to do this. One reason is that the control efficiency achievable through the use of the technology may fluctuate, so that it would not always achieve its optimal control efficiency. In that case, setting the emission limitation to reflect the highest control efficiency would make violations of the permit unavoidable. To account for this possibility, a permitting authority must be allowed a certain degree of discretion to set the emission limitation at a level that does not necessarily reflect the highest possible control efficiency, but will allow the Permittee to achieve compliance consistently. While we recognize that greater than 98% may be achievable as an average during testing, IDEM allows for sources to include a safety factor, or margin of error, to allow for minor variations in the operation of the emission units and the control device.

Therefore, the proposed VOC control of 98% is considered the top BACT for this operation.

Flare - CO

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Riverview Energy	*Proposed*	*Loading flare*	*Operate in accordance with 40 CFR 60.18*	*sweep & pilot operation: use gaseous fuel CO: 0.083 lb/MMBtu SB: 7.09E-02 lb/hr LP: 0.60 lb/hr HP: 0.60 lb/hr loading: 1.84E-02 lb/hr Flare stream operations: CO: 0.31 lb/MMBtu*	*0.20*
		Sulfur block flare			*0.77*
		Hydrogen plant flare			*6.50*
		High pressure flare			*6.50*
0.31 lb CO/MMBtu, considered as while actively flaring in conformance with 40 CFR 60.18 because that is how the emission factor is defined in AP-42, Chapter 13.5 is most stringent for CO. Therefore this is considered BACT for CO.					
Exxonmobil	TX-0796 6860, PSDTX1464 (4/20/2016)	HP Flare	NSPS §60.18	155.0 tpy	
Exxonmobil	TX-0795 83702, PSDTX843M1, PSDTX860M1 (4/18/2016)	Flares	NSPS §60.18	188.0 tpy	
Liberty Landfill	IN-0246 T181-33869-00035 (10/22/2015)	Landfill gas Flare	Good combustion practices	CO: 0.37 lb/MMBtu	
Ticona Polymers	TX-0774 123216, PSDTX1438, GHGPSDTX (11/12/2015)	Reformer	Flare (SSM)	CO: 50 ppmvd@ 3% O2 99% DRE	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Golden Pass Terminal	TX-0766 116055, PSDTX1386, GHGPSDTX 100 (9/11/2015)	Flares	None	None	
Citgo Refining and Chemicals	TX-0478 PSD-TX-408M3 (4/20/2015)	Acid gas flare	None	None	-
BASF	TX-0728 118239, N200 (4/1/2015)	Flares	None	CO: 950.41 lb/hr 98% CE	
Corpus Christi Liquefaction	TX-0679 GHGPSDTX 123 (2/27/2015)	Flares	None	None	
ExxonMobil Corporation	AK-0082 AQ1201CPT 03 (1/23/2015)	50 MMscf/yr Drilling Flare, 35 MMscf/yr HP Flare-Pilot/Purge, 20 MMscf/yr LP Flare-Pilot/Purge	None	CO: 0.37 lb/MMBtu	-
Agrium U.S. Inc.	AK-0083 AQ0083CPT 06 (1/6/2015)	1.25 MMBtu/hr Ammonia Tank Flare, 0.4 MMBtu/hr Emergency Flare, and 1.25 MMBtu/hr Small Flare	Work Practice Requirements and Limited Use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events)	CO: 0.37 lb/MMBtu	
M&G Resins	TX-0671 108446, PSDTX1352 (12/1/2014)	Flare	None	None	
Lone Star NGL Fractionators	TX-0723 N182 (11/21/2014)	Flare	NSPS §60.18	CO: 0.2755 lb/MMBtu	
This entry is not applied as BACT because the design and operating conditions are not described. Open flares, such as those proposed for Riverview Energy are not capable of being tested for emission. The AP-42 emission factor is based on operating in conformance with the requirements of 40 CFR 60.18.					
Anadarko Petroleum	FL-0347 OCS-EPA-R4015 (9/16/2014)	Boom Flare	Good combustion practices and proper flare maintenance	None	
Midwest Fertilizer	IN-0173 T129-33576-00059 (6/4/2014)	Flare	Flare minimization practices, NG pilot	CO: 0.37 lb/MMBtu 3240.16 lb/hr	
Dow Chemical	TX-0697 107153, PSDTX1328 (3/27/2014)	LP Flare	Good combustion	CO: 0.3503 lb/MMBtu	
Dow Chemical	TX-0721 100787, PSDTX1314 (1/7/2013)	Flare	None	None	
Indiana Gasification - IN	IN-0166 T147-30464-00060 (6/27/2012)	Syngas hydrocarbon flare	Flare minimization plan	CO: 172.4 lb/hr (calculated 638 lb/MMBtu)	0.27
		Acid Gas flare	Flare minimization plan	None	0.27
This source was never constructed and the permit was revoked. Therefore the reference is not considered in determining BACT					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Sabina Petrochemicals	TX-0575 41945, N018M1 (8/20/2010)	High and low pressure flares	None	None	1600 tpy
Lake Charles Cogeneration, LLC	LA-0231 PSD-LA-742 (6/22/2009)	acid gas flare	Good design and monitoring to ensure the presence of a flame at the flare tip at all the time	CO: 0.01 lb/hr max	0.27 MMBtu/hr
Navajo Refining Co.	NM-0050 PSD-NM-195-M25 (12/14/2007)	Natural gas and hydrogen flare	None	CO: 0.2 lb/hr 0.8 tpy (calculated 0.027 lb/MMBtu)	7.5
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Startup/Shutdown Flares	None	CO: 1.1 lb/MMBtu	-
		Biomethanator Flare	None	CO: 0.37 lb/MMBtu	6.4
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hydrogen Plant feed gas - flare	flare	Comply with 40 CFR 60.18 CO: 20.22 lb/hr	2472
Rohm and Haas Texas Inc.	TX-0487 PSD-TX-828M1 (3/24/2005)	Feed and exit gas flare	None	CO: 699.09 lb/hr 136.39 tpy (0.5496 lb CO/MMBtu)	-

Flare - CO2e

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Loading flare*	*Operate in accordance with 40 CFR 60.18 and other applicable NSPS and NESHAP*	*559 tpy*	*0.20*
		Sulfur block flare		*448 tpy*	*0.77*
		LP flare		*3,781 tpy*	*6.50*
		High pressure flare		*3,781 tpy*	*6.50*
BACT determined for site-specific conditions because rating and gas composition applied to other sources is not considered transferable to Riverview Energy.					
Citgo Refining and Chemicals	TX-0478 PSD-TX-408M3 (4/20/2015)	Acid gas flare	None	None	-
Exxonmobil	TX-0796 6860, PSDTX1464 (4/20/2016)	HP Flare	None	None	
Exxonmobil	TX-0795 83702, PSDTX843M1, PSDTX860M1 (4/18/2016)	Flares	None	None	
ExxonMobil Corporation	AK-0082 AQ1201CPT03 (1/23/2015)	50 MMscf/yr Drilling Flare, 35 MMscf/yr HP Flare-Pilot/Purge, 20 MMscf/yr LP Flare-Pilot/Purge	None	5317 tpy combined	-
Agrium U.S. Inc.	AK-0083 AQ0083CPT06 (1/6/2015)	1.25 MMBtu/hr Ammonia Tank Flare, 0.4 MMBtu/hr Emergency Flare, and 1.25 MMBtu/hr Small Flare	Work Practice Requirements and Limited Use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events)	59.61 ton/MMscf 1500 tpy combined	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Liberty Landfill	IN-0246 T181-33869-00035 (10/22/2015)	Landfill gas Flare	None	None	
Golden Pass Terminal	TX-0766 116055, PSDTX1386, GHGPSDTX 100 (9/11/2015)	Flares	Equipment specifications & work practices- good combustion practices	NSPS §60.18	
BASF	TX-0728 118239, N200 (4/1/2015)	Flares	None	None	
Corpus Christi Liquefaction	TX-0679 GHGPSDTX 123 (2/27/2015)	Flares	Design to 40 CFR 60.18 to achieve 99% DRE for methane		
M&G Resins	TX-0671 108446, PSDTX1352 (12/1/2014)	Flare	None	None	
Anadarko Petroleum	FL-0347 OCS-EPA-R4015 (9/16/2014)	Boom Flare	None	None	
Cronus Chemicals	IL-0114 (9/5/2014)	Ammonia Plant Flare	None	25971 tpy	
Abengoa Bioenergy	IN-0186 T129-33077-00050 (6/18/2014)	Flare	Burn NG, flare minimization plan	None	
C3 Petrochemicals	TX-0744 PSD-TX-1342-GHG (6/12/2014)	Flare	install a continuous flow monitor and composition analyzer that provides a record of the vent stream flow and composition to the flare	178 tpy 98% DRE	
Midwest Fertilizer	IN-0173 T129-33576-00059 (6/4/2014)	Flare	NG pilot, flare minimization practices	116.89 lb/MMBtu 511.81 tph	
Lone Star NGL Fractionators	TX-0747 PSD-TX-110274-GHG (4/16/2014)	Flare	monitor the BTU content on the flared gas, and will have air assisted combustion allowing for improved flare gas combustion control and minimizing periods of poor combustion. Periodic maintenance will help maintain the efficiency of the flare.	52.0 tpy rolling	
Jet Corr	IN-0228 T127-33924-00094 (3/27/2014)	Biogas flare	Good engineering design and fuel efficient design	CO2e: 3825 tpy	
Dow Chemical	TX-0697 107153, PSDTX1328 (3/27/2014)	LP Flare	None	None	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Dow Chemical	TX-0721 100787, PSDTX1314 (1/7/2013)	Flare	None	None	
Norco Hydrogen	LA-0264 PSD-LA-750(M1) (9/4/2012)	Nat gas flare	None	None	0.31
Indiana Gasification - IN	IN-0166 T147-30464-00060 (6/27/2012)	Syngas hydrocarbon flare	-	*see note	0.27
		Acid Gas flare		Flare minimization plan	0.27
This source was never constructed and the permit was revoked. Therefore the reference is not considered in determining BACT					
Sabina Petrochemicals	TX-0575 41945, N018M1 (8/20/2010)	High and low pressure flares	None	None	1600 tpy
Navajo Refining Co.	NM-0050 PSD-NM-195-M25 (12/14/2007)	Natural gas and hydrogen flare	None	None	7.5
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Startup/Shutdown Flares	None	None	-
		Biomethanator Flare	None	None	6.4
Rohm and Haas Texas Inc.	TX-0487 PSD-TX-828M1 (3/24/2005)	Feed and exit gas flare	None	None	-

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

(a) The units shall burn only natural gas and process off-gas as supplemental and pilot fuel.

(b) The Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the flares shall be as follows:

(1) Particulate matter emissions while operating in sweep and pilot mode shall not exceed:

Emission Limitations			
Unit ID	**Pollutant**	**lb/MMBtu**	**lb/hr**
HP Flare	PM (filterable)	0.0019	0.014
	PM_{10}	0.0074	0.053
	$PM_{2.5}$	0.0074	0.053
LP Flare	PM (filterable)	0.0019	0.014
	PM_{10}	0.0074	0.053
	$PM_{2.5}$	0.0074	0.053
SB Flare	PM (filterable)	0.0019	1.62E-03
	PM_{10}	0.0074	6.32E-03

Emission Limitations			
Unit ID	**Pollutant**	**lb/MMBtu**	**lb/hr**
	$PM_{2.5}$	0.0074	6.32E-03
Loading Flare	PM (filterable)	0.0019	4.22E-04
	PM10	0.0074	1.64E-03
	PM2.5	0.0074	1.64E-03

(2) The HP Flare and LP Flare shall operate with no visible emissions, except for periods not to exceed a total of five (5) minutes during any two (2) consecutive hours when flaring a process stream.

(c) The Best Available Control Technology (PSD BACT) for SO_2 for the flares shall be as follows:

(1) The Permittee shall burn only natural gas and process off-gas in any flare as supplemental or pilot fuel gas.

(2) SO_2 emissions while operating in sweep and pilot mode shall not exceed:

SO_2 Emission Limitations	
Unit ID	**lb/hr**
HP Flare	0.013
LP Flare	0.013

(3) SO_2 emissions from the SB Flare shall not exceed 0.069 lb/hr when operating in sweep and pilot mode.

(4) SO_2 emissions from the Loading Flare shall not exceed 0.069 lb/hr when operating in pilot mode.

(d) The Best Available Control Technology (PSD BACT) for NOx for the flares shall be as follows:

(1) NOx emissions while operating in sweep and pilot mode shall not exceed:

NOx Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
HP Flare	0.099	0.71
LP Flare	0.099	0.71
SB Flare	0.099	8.46E-02
Loading Flare	0.099	2.20E-02

(2) NOx emissions shall not exceed 0.068 lb/MMBtu (LHV) when flaring a process stream.

(e) The Best Available Control Technology (PSD BACT) for VOC for the flares shall be as follows:

(1) VOC emissions while operating in sweep and pilot mode shall not exceed:

VOC Emission Limitations		
Unit ID	lb/MMBtu	lb/hr
HP Flare	0.0054	0.039
LP Flare	0.0054	0.039
SB Flare	0.0054	4.62E-03

(2) VOC destruction and removal efficiency shall not be less than 98% when flaring a process stream.

(3) VOC emissions while operating in pilot mode shall not exceed:

VOC Emission Limitations		
Unit ID	lb/MMBtu	lb/hr
Loading Flare	0.0054	1.20E-03

(f) The Best Available Control Technology (PSD BACT) for CO for the flares shall be as follows:

(1) CO emissions while operating in purge and pilot mode shall not exceed:

CO Emission Limitations		
Unit ID	lb/MMBtu	lb/hr
HP Flare	0.083	0.60
LP Flare	0.083	0.60
SB Flare	0.083	7.09E-02
Loading Flare (pilot only)	0.083	1.84E-02

(2) CO emissions shall not exceed 0.31 lb/MMBtu (LHV) when flaring a process stream.

(g) Carbon dioxide equivalent (CO_2e) emissions, as defined at 40 CFR 98.6, from the flares listed in the table below when operating in purge and pilot mode shall not exceed the values shown per twelve (12) consecutive month period, with compliance determined at the end of each month.

Emission Limitations	
Unit ID	CO_2e Limit
Sulfur Block Flare	448
LP Flare	3,781
HP Flare	3,781
Loading Flare	559

VOC BACT Analysis
Tanks

Step 1: Identify Potential Control Technologies

Add-on controls:

There are two general categories of control methods for volatile organic compounds (VOCs): destruction methods and reclamation methods. Destruction control methods reduce the VOC concentration by high temperature oxidation into carbon dioxide and water vapor. Reclamation control methods consist of capturing VOCs for reuse or disposal. These are discussed in more detail below.

Destruction Control Methods
The destruction of organic compounds usually requires temperatures ranging from 1200°F to 2200°F for direct thermal oxidizers or 600°F to 1200°F for catalytic systems. Combustion temperature depends on the chemical composition and the desired destruction efficiency. Carbon dioxide and water vapor are the typical products of complete combustion. Turbulent mixing and combustion chamber retention times of 0.5 to 1.0 seconds are needed to obtain high destruction efficiencies.

Fume oxidizers typically need supplemental fuel. Concentrated VOC streams with high heat contents obviously require less supplementary fuel than more dilute streams. VOC streams sometimes have a heat content high enough to be self-sustaining, but a supplemental fuel-firing rate equal to about 5% of the total oxidizer heat input is usually needed to stabilize the burner flame. Natural gas is the most common fuel for VOC oxidizers, but fuel oil is an option in some circumstances.

Destruction control methods include:

(a) Thermal Oxidizer:

Thermal oxidation is the process of oxidizing VOC in a waste gas stream by raising the temperature above the VOC's auto-ignition point in the presence of oxygen for sufficient time to completely oxidize the organic contaminants to carbon dioxide and water. The residence time, temperature, flow velocity and mixing, and the oxygen concentration in the combustion chamber affect the oxidation rate and destruction efficiency. Thermal oxidizers operating costs are relatively high, since they typically require combustion of an auxiliary fuel (e.g., natural gas) to maintain combustion chamber temperature high enough to completely oxidize the contaminant gases. In general, thermal oxidizers are less efficient at treating waste gas streams with highly variable flowrates, since the variable flowrate results in varying residence times, combustion chamber temperature, and poor mixing. In addition, thermal oxidizers are also not generally cost-effective for low-concentration, high-flow organic vapor streams.

Thermal oxidizers can achieve 95-99.99+% VOC control efficiency and can be used over a wide range of organic vapor concentrations, but perform best at inlet concentrations of around 1,500-3,000 ppmv. Thermal oxidizers are typically designed to have a residence time of 0.3 to 1.0 second and combustion chamber temperatures between 1,200 and 2,000°F. In order to meet 98% or greater control or a 20 parts per million by volume (ppmv) compound exit concentration of non-halogenated organics, thermal oxidizers should typically be operated at a residence time of at least 0.75 seconds, a combustion chamber temperature of at least 1600°F, and with proper mixing. While thermal oxidation provides efficient VOC control, other pollutants such as nitrogen oxides and carbon monoxide are formed from the combustion process.

Thermal oxidizers are not generally recommended for controlling gases containing halogen- or sulfur-containing compounds, because of the formation of hydrogen chloride, hydrogen fluoride gas, sulfur dioxide, and other highly corrosive acid gases. It may be necessary to install a post-oxidation acid gas treatment system in such cases, depending on the outlet concentration. This would likely make incineration an uneconomical option. For halogenated VOC streams, a combustion temperature of 2000°F, a residence time of 1.0 second, and use of an acid gas scrubber on the outlet is recommended.

The three types of thermal oxidation systems include direct flame, recuperative, and regenerative thermal oxidizers, which are differentiated by the type of heat recovery equipment used.

(1) Direct Flame Thermal Oxidizer

A direct flame thermal oxidizer is comprised of a combustion chamber and does not include any heat recovery of exhaust air by a heat exchanger.

(2) Recuperative Thermal Oxidizer

A recuperative thermal oxidizer is comprised of the combustion chamber, a heat exchanger for preheating the untreated VOC gas stream, and, if cost-effective, a secondary energy recovery heat exchanger. In a recuperative thermal oxidizer, the untreated VOC gas stream entering the oxidizer is preheated using the heat content of the treated gas stream exiting the oxidizer using a heat exchanger, resulting in improved oxidizer efficiency and reduced auxiliary fuel usage. Recuperative thermal oxidizers usually are more economical than direct flame thermal oxidizers because they typically recover 40 to 70% of the waste heat from the exhaust gases.

(3) Regenerative Thermal Oxidizer

A regenerative thermal oxidizer typically consists of a set of 2 or 3 packed ceramic beds that are used to recover heat from hot combustion gases that are generated during combustion of the VOC gas stream and auxiliary fuel, resulting in improved oxidizer efficiency and reduced auxiliary fuel usage. An "inlet" bed is used to pre-heat the untreated VOC gas stream, an "outlet" bed is used to recover heat from the treated gas stream, and one bed is in a purge cycle. The purge cycle is needed to prevent emission spikes each time the gas flow is redirected. The oxidizer is operated on a rotating schedule, where the gas flow through the ceramic beds is redirected periodically using a set of gas flow dampers. Once the heat energy of the "inlet" ceramic bed has been depleted, the flow through the system is redirected so that the untreated VOC gas stream entering the oxidizer is directed through the previously heated "outlet" ceramic bed. Regenerative thermal oxidizers have much higher heat recovery efficiencies than recuperative thermal oxidizers, recovering 85 to 95% of the heat from the treated gas stream, and therefore have lower auxiliary fuel requirements. However, compared to direct flame and recuperative thermal oxidizers, regenerative thermal oxidizers typically have higher capital (equipment and installation) costs, are larger and heavier, and have higher maintenance costs.

(b) Catalytic Oxidizer:

Catalytic oxidation is the process of oxidizing organic contaminants in a waste gas stream within a heated chamber containing a catalyst bed in the presence of oxygen for sufficient time to completely oxidize the organic contaminants to carbon dioxide and water. The catalyst is used to lower the activation energy of the oxidation reaction, enabling the oxidation to occur at lower reaction temperatures compared to thermal oxidizers. The residence time, temperature, flow velocity and mixing, the oxygen concentration, and type of catalyst used in the combustion chamber affect the oxidation rate and destruction efficiency. Catalytic oxidizers typically require combustion of an auxiliary fuel (e.g., natural gas) to maintain combustion chamber temperature high enough to completely oxidize the contaminant gases. Catalytic oxidizers operate at lower temperatures and require less fuel than thermal oxidizers, they have a smaller footprint, and they need little or no insulation. The catalyst bed is usually composed of the following: (1) the substrate, typically ceramic or metal honeycombs, grids, mesh pads, or beads; (2) the carrier, a high surface area inorganic material such as alumina that is bonded to the substrate that contains a complex pore structure; and (3) the catalyst, a thin layer of material deposited onto the carrier. The most widely used catalysts for VOC oxidation are noble metals, such as platinum, palladium and rhodium or mixtures thereof. Base metal catalysts, such as oxides of chromium, cobalt, copper, manganese, titanium, and vanadium may also be used for VOC oxidation. Similar to thermal oxidizers, catalytic oxidizers may use regenerative or recuperative heat recovery to reduce auxiliary fuel requirements, where the untreated VOC gas stream entering the catalytic oxidizer is preheated using the heat content of the treated gas stream exiting the catalytic oxidizer.

Catalytic oxidizers can achieve 90-99% VOC control efficiency, depending on the oxidizer design and waste stream characteristics. Catalytic oxidizers are typically designed to have a residence time of 0.5 seconds or less and combustion chamber temperatures between 600 and 1,200°F. Catalytic oxidation is most suited to waste gas streams with little variation in the flow rate and type and concentration of VOC to be treated. In addition, catalytic oxidizers should not be used for waste gas streams that have a high concentration of particles, silicone, sulfur, halogen compounds, and/or heavy hydrocarbons that can cause fouling or masking of the catalyst, and for waste gas streams that contain metals such as mercury, phosphorus, arsenic, antimony, bismuth, lead, zinc, and/or tin that can cause catalyst poisoning.

(c) Flare:

Flaring is the process of oxidizing VOC in a waste gas stream by piping the waste gas to a remote, usually elevated location and burning it in a flame using a specially designed burner tip, auxiliary fuel, and steam or air to promote mixing. Flares are generally categorized in two ways: (1) by the height of the flare tip (i.e., ground or elevated), and (2) by the method of enhancing mixing at the flare tip (i.e., steam-assisted, air-assisted, pressure-assisted, or non-assisted). Flares can be used to control almost any VOC stream, and can typically handle large fluctuations in VOC concentration, flow rate, heating value, and inert species content. Flaring is appropriate for continuous, batch, and variable flow vent stream applications, but the primary use is that of a safety device used to control a large volume of pollutant resulting from upset conditions. Flares have primarily been used in petroleum production, petroleum refineries, and chemical plants to control waste gas streams containing low molecular weight VOC with high heating values.

A properly operated flare can achieve 98+% VOC control efficiency when controlling emission streams with heat contents greater than 300 British thermal units per standard cubic foot (Btu/scf). If the waste gas stream has a heat content less than 300 Btu/scf, auxiliary fuel must be introduced in sufficient quantity to make up the difference. The VOC destruction efficiency of a flare depends upon the waste gas characteristics (density, flammability, heating value, and VOC component autoignition temperatures) and the combustion zone conditions (temperature, residence time, mixing, and available oxygen). While flares can provide efficient VOC control, other pollutants such as nitrogen oxides (NOx) and carbon monoxide (CO) are formed from the combustion process. Flares are not generally recommended for controlling gases containing halogen- or sulfur-containing compounds, because of the formation of hydrogen chloride, hydrogen fluoride gas, sulfur dioxide, and other highly corrosive acid gases.

Reclamation Control Methods

Organic compounds may be reclaimed by one of three possible methods: adsorption, absorption (scrubbing), or condensation. In general, the organic compounds are separated from the emission stream and reclaimed for reuse or disposal. Depending on the nature of the contaminant and the inlet concentration of the emission stream, recovery technologies can reach efficiencies of 98%.

(d) Carbon Adsorption Unit:

Carbon adsorption is a process where VOCs are removed from a waste gas stream when it is passed through a bed containing activated carbon particles, which have a highly porous structure with a large surface-to-volume ratio. Carbon adsorption systems usually operate in two phases: adsorption and desorption. During adsorption, the majority of the VOC molecules migrate from the gas stream to the surface of the activated carbon (through the activated carbon pores) where it is lightly held to the surface by weak intermolecular forces known as van der Waals' forces. As the activated carbon bed approaches saturation with VOC, its control efficiency drops, and the bed must be taken offline to be replaced or regenerated. Typically, two activated carbon beds are utilized on a rotating schedule, where a second bed (containing fresh or previously regenerated activated carbon) is brought online to continue controlling the VOC gas stream while the first bed is being replaced or regenerated. In regenerative systems, most VOC gases can be desorbed and removed from the activated carbon bed by heating the bed to a sufficiently high temperature, usually via steam or hot air, or by reducing the pressure within the bed to a sufficiently low value (vacuum desorption). The regenerated activated carbon can be reused and the VOCs that are removed from the bed can be reclaimed or destroyed.

Carbon adsorber size and purchase cost depend primarily on the gas stream volumetric flow rate, temperature, pressure, VOC composition, VOC mass loading, and moisture and particulate contents. The adsorptive capacity of an activated carbon bed for a VOC gas tends to increase with the VOC gas phase concentration, molecular weight, diffusivity, polarity, and boiling point. Carbon adsorption systems can be used for VOC gas concentrations from less than 10 ppm to approximately 10,000 ppm. Carbon adsorption systems (in general) are usually limited to waste gas streams with VOC compounds having a molecular weight of more than 50 and less than approximately 200 lb/lb-mole, since low molecular weight organics usually do not adsorb sufficiently and high molecular weight compounds are difficult to desorb and remove during the desorption cycle. Industrial applications of adsorption systems include control for dry cleaning, degreasing, paint spraying, solvent extraction, metal foil coating, paper coating, plastic film coating, printing, pharmaceuticals, rubber, linoleum, and transparent wrapping.

Carbon adsorption systems can achieve 95-99% VOC control efficiency. Carbon adsorption system control efficiency increases with reduced VOC gas stream temperatures. Therefore, high temperature VOC gas streams are typically cooled prior to entry into the activated carbon bed. Particulate matter and high moisture concentrations present in the gas stream compete with the VOC for pore space within the activated carbon and thereby reduce the VOC adsorptive capacity and control efficiency of the carbon adsorption systems. In addition, particulate matter and moisture can become entrained within the carbon bed, causing operating problems such as increased pressure drop across the bed.

(e) Gas Absorption (wet scrubber):

A wet scrubber is an absorption system in which a waste gas stream is interacted with a scrubbing fluid inside a contact chamber in order to strip particulate or gaseous pollutants from the waste gas stream through the processes of diffusion and dissolution. In many cases, an additive such as an acid, a base, or a VOC oxidizing agent is dissolved in the scrubbing fluid so that the dissolved gaseous pollutant chemically reacts with the scrubbing fluid to form a non-volatile or soluble product, thereby allowing additional gaseous pollutant to be absorbed by the scrubbing fluid. The four types of wet scrubber systems include packed towers, plate (or tray) columns, venturi scrubbers, and spray chambers. Gas and liquid flow through an absorber may be countercurrent, crosscurrent, or cocurrent. When used as an emission control technique, wet scrubbers are typically used for controlling particulate, acid gases, halogen gases, and highly soluble gases such as sulfur dioxide and ammonia.

If a wet scrubber is used for VOC control, the scrubbing fluid chosen should have a high solubility for the VOC gas, a low vapor pressure, a low viscosity, and should be relatively inexpensive. Water is the most commonly used scrubbing fluid for absorbing highly water-soluble (hydrophilic) VOC compounds such as methanol, ethanol, isopropanol, butanol, acetone, and formaldehyde. Other scrubbing fluid such as mineral oils, nonvolatile hydrocarbon oils, and aqueous solutions containing surfactants or amphiphilic block copolymers may be used for absorbing water-insoluble (hydrophobic) VOC compounds. Physical absorption is typically enhanced by lower temperatures, greater scrubbing fluid contacting time and surface area, higher scrubbing fluid to VOC ratio, and higher VOC concentrations in the gas stream.

Wet scrubber systems can achieve 70-99% VOC control efficiency, depending on the VOC solubility in the scrubbing fluid, the VOC-scrubbing fluid temperature, the scrubbing fluid contacting time and surface area, the scrubbing fluid to VOC ratio, the VOC concentration in the gas stream, and whether the scrubbing fluid contains a VOC oxidizing agent. Wet scrubber absorption system control efficiency increases with reduced VOC gas stream temperatures. Therefore, high temperature VOC gas streams are typically cooled prior to entry into the wet scrubber. When used to control VOC, the spent scrubbing fluid must be regenerated, treated, or shipped offsite for proper disposal.

(f) Condensation Unit:

Condensation is the separation of VOCs from an emission stream through a phase change, by either increasing the system pressure or, more commonly, lowering the system temperature below the dew point of the VOC vapor. Three types of condensers are used for air pollution Controls: (1) conventional non-refrigeration systems (such as cold-water direct contact condensers similar to wet scrubbers and cold-water indirect heat exchangers); (2) refrigeration systems (including mechanical compression refrigeration using chlorofluorocarbons (CFCs) and hydrofluorocarbons (HFCs) and Reverse Brayton Cycle refrigeration); and (3) cryogenic systems that utilize liquid nitrogen (including direct contact condensers and indirect heat exchangers).

Condensation units control VOC more efficiently when they are used for gas streams containing high concentrations of VOC and with low exhaust volumes. Condensation units are typically utilized at sources where there is a significant cost benefit to recovering the organic liquid for reuse, where the recovered organic liquids do not contain multiple organic compounds or water that require separation, and where the heat content of gas stream will not overload the refrigeration system. In addition, condensation units are typically used only on gas streams that have little or no particulate contamination, which can cause fouling within the condensation equipment and reduced heat transfer efficiency. Some industrial applications where refrigerated condensers are used include the dry cleaning industry, degreasers using VOC or halogenated solvents, transfer of volatile organic liquid or petroleum products, and vapors from storage vessels.

Cold-water (non-refrigeration) condensation systems can achieve 90-99% VOC control efficiency, depending on the vapor pressures of the specific compounds. Condensation units using mechanical compression refrigeration (using CFC or HFC) can achieve 90+% VOC control efficiency, condensation units using Reverse Brayton Cycle refrigeration can achieve 98% VOC control efficiency, and condensation units using cryogenic (liquid nitrogen) cooling can achieve 99+% VOC control efficiency.

Other Control Methods

(g) Bio-filtration is a process in which a waste gas stream is passed through a bed of peat, compost, bark, soil, gravel, or other inorganic media in order to strip organic contaminant gases from the waste gas stream through the process of dissolution in the bed moisture and adsorption to the bed media. Under aerobic conditions, microorganisms naturally present in the bed oxidize the organic contaminant gases within the bed to carbon dioxide, water, and additional biomass through metabolic processes. If the temperature of the waste gas stream is too high, the gas stream must be cooled to an optimum temperature before it can be treated in the biofilter in order to maintain the viability of the microorganisms. In addition, the bed must be monitored and maintained at an optimum moisture content and pH in order to prevent cracking of the bed media and to maintain the viability of the microorganisms.

Bio-filtration systems are designed to follow three basic steps. First, a pollutant in the gas phase is passed through a biologically active packed bed. The pollutant then diffuses into the biofilm immobilized on the packing medium. Finally, microorganisms growing in the biofilm oxidize the pollutant as a primary substrate or co-metabolite and in the process convert contaminants into the benign end products of carbon dioxide, water and additional biomass.

Three primary bioreactor configurations are available to treat stationary sources of air pollution: bio-filters, bio-trickling filters, and bio-scrubbers.

(1) Bio-Filters

Bio-filters are the simplest and oldest of the three vapor-phase bioreactors and involve passing a contaminated air stream through a reactor containing biologically-active packing material. The contaminants are transferred from the air stream into a bio-film immobilized on the support media and are converted by the microorganisms into CO2, water, and additional biomass. Moister is typically supplied to the bio-film in a humid inlet waste gas stream. Packing media used in bio-filter beds can be broadly categorized as either "natural" or "synthetic". Natural media include wood chips, peat, and compost, with compost by far the most widely used. Synthetic media include activated carbon, ceramic pellets, polystyrene beads, ground tires, plastic media, and polyurethane foam. Natural organic packing media generally contain a supply of nutrients as a naturally occurring component of the packing itself. When a synthetic support medium is used, nutrients must be added for microbial growth.

(2) Bio-Trickling Filters

Bio-trickling filters are similar to bio-filters with the exception that there is a liquid nutrient medium continuously recalculating through the column. To facilitate the recirculation of the liquid phase, rigid synthetic media is used as the packing medium. Microorganisms grow primarily as a fixed film on inert packing media but may also be present in the liquid phase because they can both grow suspended in the liquid phase and because the flowing liquid imparts sufficient force to detach biomass from the solid support media. Contaminants are transferred from the air stream into the liquid phase and bio-film for subsequent degradation.

Potential disadvantages of bio-trickling filter operations include: clogging of the pore space if the filter is treating high VOC loads or if the filter is provided excess nutrients, and the need to manage the liquid stream. An additional disadvantage is that bio-trickling filters may have more difficulty treating poorly soluble compounds since the specific surface are in bio-tricking filters is generally lower.

(3) Bio-Scrubbers

Bio-scrubbers combine physical and chemical treatment with a biological treatment in two separate reactors. In the first reactor, the contaminated air stream is contacted with water in a reactor packed with inert media, resulting in contaminant transfer from the air phase to the liquid phase. The liquid is then directed into an activated sludge reactor where the contaminants are biologically degraded. The separated activated sludge tank allows the reactor to treat higher concentrations of compounds than bio-filters can handle. In addition since compound transfer and degradation occur in separate reactors, optimization of each reactor can take place separately. As with bio-trickling filters, bio-scrubbers offer greater operator control over nutrient supply, acidity, and the build-up of toxic by-products.

A potential disadvantage of bio-scrubbers is that slower growing microorganisms may be washed out of the system and disposal of excess sludge is required.

Other control options

(a) Submerged Fill

Loading losses occur in cargo carrier loading as the organic vapors are displaced as the liquid product is loaded. The organic vapors can contain residual vapors from the last product loaded, vapors transferred to the tank in a vapor balance system and vapors generated in the tank as new product is loaded. The amount of vapors generated can be controlled by the type of loading method used. In splash loading, the fill pipe is only lowered part way into the tank. This results in large amounts of turbulence in the liquid and results in close contact of the VOC with the vapor which increase emissions. The submerged fill method is an alternate filling method used to reduce the amount of vapor/liquid contact. In the submerged fill method, the fill pipe extends below the liquid surface. As the liquid is transferred to the tank, the submerged fill pipe significantly reduces turbulence, air/liquid contact and results in lower overall VOC emissions.

(b) Tank Color

Color selection can contribute to elevated emissions of VOC. Black or darker colored tanks absorb more frequencies of light. This energy is transferred to the contents of the tank as heat through conduction in the tank wall. As the liquid heats, the vapor pressure rises and potential VOC emissions increase. The reverse is true for light colored or reflective tanks.

(c) Floating Roof Tanks
VOC emissions from storage tanks may be controlled through the use of floating roof tanks. Floating tanks control VOC emissions by reducing the amount of organic vapor that is in the tank at any one time. This is accomplished by having a roof that floats on top of the liquid in the tank and is sealed in a manner that does not allow vapor loss around the edges of the floating roof. By floating the roof, no vapor zone above the liquid can form.

Step 2: Eliminate Technically Infeasible Options

There are some add-on control devices that are considered technically feasible, however, due to the relatively low PTE of VOC for each tank, there are no add-on control devices that are considered economically feasible.

Submerged fill and tank color are considered feasible control options.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Since floating roof tanks, submerged fill and tank color are considered the only feasible control options, a ranking is not necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following tables summarize other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Riverview Energy Corporation
Proposed Organic Liquid Tanks BACT

(a) *VOL (as defined at 40 CFR 60.111b) tanks, T1, T2, and T6, shall use internal floating roofs.*
(b) *Emissions from the slop tank, T16, shall be controlled by the LP Flare at all times and the slop tank throughput shall not exceed the value shown in the table below per twelve (12) consecutive month period with compliance determined at the end of each month.*
(c) *Emissions from the sour water tanks, T18 - T21, shall be controlled by the Sulfur Block Flare at all times and the sour water tank throughputs shall each not exceed the values shown in the table below per twelve (12) consecutive month period with compliance determined at the end of each month.*
(d) *All tanks shall use white tank shells.*
(e) *All tanks shall use submerged filling.*
(f) *All tanks shall use good maintenance practices based on generally-accepted industry standards, including but not limited to API 650 Welded Steel Tanks for Oil Storage and API 653 Tank Inspection, Repair, Alteration, and Reconstruction.*
(g) *Tanks shall comply with the following limitations:*

Tank ID	Product Stored	Storage Temperature (°F)	VOC Emissions Limit (tons/yr)	Throughput Limit (kgal/yr)
T1	Naphtha Product	ambient	1.15	-
T2	Naphtha Product	ambient	1.15	-
T3	Diesel Product	ambient	2.29	-
T4	Diesel Product	ambient	2.29	-
T5	Diesel Product	ambient	2.29	-
T6	Naphtha Product	ambient	1.15	-
	Diesel Product	ambient	0.17	-
T10	Residue	505	1E-04	-
T11	Residue	505	1E-04	-
T12	Residue	505	1E-04	-
T13	VGO	505	0.175	-
T14	VGO	505	0.175	-
T16	Slop tank	ambient	-	305,467
T17	Diesel Fuel	ambient	1.14E-02	-
T18	Non-Phenolic Sour Water	ambient	-	462,829
T19	Non-Phenolic Sour Water	ambient	-	462,829
T20	Non-Phenolic Sour Water	ambient	-	462,829
T21	Phenolic Sour Water	ambient	-	4,628
T22	Stripped Non-Phenolic Sour Water	ambient	0.48	-
T23	Stripped Phenolic Sour Water	ambient	0.48	-
T24	Amine Surge/Deinventory	ambient	0.48	-
T25	Fresh Amine	ambient	0.48	-
T26	Amine Containment	ambient	0.48	-
EU-6005	Emergency generator diesel fuel	ambient	1.14E-02	-
EU-6008	Emergency fire pump diesel fuel	ambient	1.14E-02	-

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Capacity (gallons)
Magellan Pipeline Terminals, LP	TX-0613 94433, N134 (4/23/2012)	tanks - misc	Internal floating roof	9.0 lb/hr (8.0 ton/yr)	various from 1.68 to 14.7 million gal
An internal floating roof is the most stringent control for tanks containing Volatile Organic Liquids as defined at 40 CFR 60.111b. Therefore, this has been determined to be BACT for tanks T1, T2, and T6.					
ENI US Operating Co., Inc.	FL-0328 OCS-EPA-R4007 (10/27/2011)	Various diesel storage tanks ranging from 50 gal to 610,000 gal	Use of good maintenance practices based on the current manufacturer's specifications for each tank	0.27 ton/yr	-
This has been determined BACT for all tanks.					
Union Co. Lumber Co.	AR-0124 2348-AOP-R0 (8/3/2015)	diesel oil tanks	light color tanks	0.4 lb/hr	
This has been determined BACT for all tanks.					
Agrium	AK-0083 AQ0083CPT06 (1/6/2015)	Two Methyl-diethanol Amine (MDEA) Storage Tanks	Submerged fill	0.002 tpy	
Submerged fill has been determined BACT for all tanks.					
In addition, the source has proposed the use of a flare for tanks T16, and T18-T21. Therefore, this has been determined to be BACT for tanks T16, and T18-T21.					
CF Industries Nitrogen	IA-0106 PN 13-037 (7/12/2013)	Diesel Belly Tanks	None	VOC: 0.1 ton/yr	various
		Methyl-diethanol Amine (MDEA) Storage Tank	Nitrogen blanket	0.1 tpy	
A nitrogen blanket is not considered BACT for the MDEA tanks, T24-T26. A nitrogen blanket is not a control technology for VOC emissions from a tank because the blanket does not affect the partial pressure of the stored liquid or the vapor phase concentration exhausted from the tank.					
LBC Houston	TX-0783 123325, N206 (2/6/2016)	tanks (24) vapor pressure <0.52 psia	submerged fill pipes and are painted white	0.01 tpy	
		tanks (16)	internal floating roofs with welded seams, mechanical shoe primary seals, rim-mounted secondary seals adn welded deck seams and vapor combustor	0.26 tpy for (6) and 0.15 tpy for (10) NSPS Kb 99.9% CE	
Ticona Polymers	TX-0774 123216, PSDTX1438 and GHGPSDTX (11/12/2015)	crude and methanol tanks	Submerged fill, white tanks with internal floating roofs	NSPS Kb & MACT G 6.86 tpy	
Union County Lumber Company	AR-0124 2348-AQP-R0 (8/3/2015)	diesel storage tanks	None	VOC: 0.4 lb/hr	various
		oil storage tanks	None	VOC: 0.3 lb/hr	various
Florida Power and Light Co.	FL-0346 0110037-011-AC (4/22/2014)	Three ULSD fuel oil storage tanks	Pressure relieve valves/vapor condensers, or tanks with internal floating roofs or equivalent		-
Old Dominion Electric Corp.	MD-0042 CPCN Case No. 9327 (4/8/2014)	fuel oil tanks	LAER: periodic maintenance to minimize fugitive emissions	0.001 ton/yr	80000, 150000, 75000 bbl
Indiana Gasification, LLC	IN-0166 T147-30464-00060 (6/27/2012)	Sulfuric acid tanks	fixed roof and submerged fill	none	866500 gal each
This source was never constructed and the permit was revoked. Therefore the reference is not considered in determining BACT					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Capacity (gallons)
Valero Refining	LA-0213 PSD-LA-619(M5) (11/17/2009)	tanks - for light materials, sour water, naphtha, raffinate	Floating roofs	Comply with 40 CFR 60, Subpart Kb or 40 CFR 63, Subpart CC	various
This reference is not considered BACT for the sour water tanks. IFR control requirements in 40 CFR 60, Subpart Kb are not applicable because the sour water stream does not contain volatile organic liquids as defined at 40 CFR 60.111b, the sour water will not emit VOC as defined at 40 CFR 51.100. Requirements of 40 CFR 63, Subpart 63 are not applicable to the sour water tanks because the sour water does not contain hazardous air pollutants listed in Table 1, Appendix to Subpart CC of Part 63.					
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Diesel Tank (Fixed Roof)	Submerged fill	VOC: 0.8 ton/yr	262,500 gal/day
		Naphtha Tank (Internal floating roof)	Submerged fill and floating roof	VOC: 0.88 ton/yr 99% CE	
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Conoco Phillips	IL-0103 06050052 (8/5/2008)	sour water tank	Internal floating roof	none	3,360,000 gal
This reference is not considered BACT for the sour water tanks at the proposed source. IFR control requirements in 40 CFR 60, Subpart Kb are not applicable because the sour water stream does not contain volatile organic liquids as defined at 40 CFR 60.111b, the sour water will not emit VOC as defined at 40 CFR 51.100. Requirements of 40 CFR 63, Subpart 63 are not applicable to the sour water tanks because the sour water does not contain hazardous air pollutants listed in Table 1, Appendix to Subpart CC of Part 63.					
Navajo Refining Co., LLC	NM-0050 PSD-NM-195-M25 (12/14/2007)	tanks - naphtha, or vol liq up to 11.0 psi	External floating roof	none	100,000 bbl thrpt (4.2 million gal)
		Sour Water Tank and Naphtha tank	External floating roof	none	20000 BBL
BACT for the proposed source includes internal floating roofs for VOL tanks. External floating roofs are not considered a more restrictive control. This reference is not considered BACT for the sour water tanks at the proposed source. IFR control requirements in 40 CFR 60, Subpart Kb are not applicable because the sour water stream does not contain volatile organic liquids as defined at 40 CFR 60.111b, the sour water will not emit VOC as defined at 40 CFR 51.100. Requirements of 40 CFR 63, Subpart 63 are not applicable to the sour water tanks because the sour water does not contain hazardous air pollutants listed in Table 1, Appendix to Subpart CC of Part 63.					
Progress Energy Florida	FL-0285 PSD-FL-381, 1030011-010-AC (1/26/2007)	tanks - Distillate	None	keep records establishing vapor pressure is below 3.5KPa	3.5 million gal. (ea.)
Florida Power and Light Co.	FL-0286 PSD-FL-354, 0990646-001-AC (1/10/2007)	tanks - Distillate (ULSD)	None	keep records establishing vapor pressure is below 3.5KPa; MSDS is acceptable	6.3 million gal. (ea.)
Marathon Petroleum Co. LLC	LA-0211 PSD-LA-719 (12/27/2006)	tanks - petroleum products	fixed roof and internal floating roofs	40 CFR 63 Subpart CC	various
Citgo Refining and Chemicals Co.	TX-0478 PSD-TX-408M3 (4/20/2015)	tanks - petroleum products	None	1.6 lb/hr (3.9 tpy)	various
		tanks - petroleum products	None	4.4 lb/hr (3.3 tpy)	various
		tanks - petroleum products	None	0.8 lb/hr (1.4 tpy)	various
Continental Carbon Co.	TX-0464 P1014 (3/18/2005)	tanks - low vapor pressure oil	Fixed roof	0.01 lb/hr	NA

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Control Technology Review; Requirements), IDEM has established the following BACT:

(a) All tanks shall use white tank shells.
(b) All tanks shall use submerged filling.
(c) All tanks shall use good maintenance practices based on generally-accepted industry standards, including but not limited to API 650 Welded Steel Tanks for Oil Storage and API 653 Tank Inspection, Repair, Alteration, and Reconstruction.
(d) Tanks shall comply with the following controls and limitations:

Tank ID	Product Stored	Storage Temperature (°F)	Vapor Pressure[1] (psia)	Throughput Limit[2] (kgal/yr)
T1	Naphtha Product	ambient	1.15	-
T2	Naphtha Product	ambient	1.15	-
T3	Diesel Product	ambient	2.29	-
T4	Diesel Product	ambient	2.29	-
T5	Diesel Product	ambient	2.29	-
T6	Naphtha Product	ambient	1.15	-
	Diesel Product	ambient	0.17	-
T10	Residue[3]	505	1E-04	-
T11	Residue	505	1E-04	-
T12	Residue	505	1E-04	-
T13	VGO	505	0.175	-
T14	VGO	505	0.175	-
T16	Slop tank[4]	ambient	-	305,467
T17	Diesel Fuel	ambient	1.14E-02	-
T18	Non-Phenolic Sour Water[5]	ambient	-	462,829
T19	Non-Phenolic Sour Water	ambient	-	462,829
T20	Non-Phenolic Sour Water	ambient	-	462,829
T21	Phenolic Sour Water	ambient	-	4,628
T22	Stripped Non-Phenolic Sour Water	ambient	0.48	-
T23	Stripped Phenolic Sour Water	ambient	0.48	-
T24	Amine Surge/Deinventory	ambient	0.48	-
T25	Fresh Amine	ambient	0.48	-
T26	Amine Containment	ambient	0.48	-
EU-6005[6]	Emergency generator diesel fuel	ambient	1.14E-02	-
EU-6008	Emergency fire pump diesel fuel	ambient	1.14E-02	-

Notes:
1. *Vapor pressure for products stored at ambient temperature taken at the highest monthly average daily temperature for Evansville, IN from meteorological data in TANKS 4.0.9d, 78.3°F.*
2. *kgal/yr = kgal per twelve (12) consecutive month period, with compliance determined at the end of each month. kgal = 1,000 gallons*
3. *Vapor pressure at elevated storage temperature from process modeling provided by the source.*
4. *Diesel fuel taken as representative of slop oil*
5. *Vapor pressure of wastewater streams and 40% MDEA solution ("amine") taken as water at 78.3°F, Table 3-5, Perry's Chemical Engineers' Handbook, 6th Ed., because of the low partial pressures of the organic compounds.*
6. *Throughput for emergency engine fuel tanks does not include operation during emergencies.*

VOC BACT Analysis
Loading Racks

Step 1: Identify Potential Control Technologies

Cooling and Condensing System

Refrigerated condensers, also sometimes known as Vapor Recovery Units (VRUs) are used as air pollution control devices for treating emission streams with high VOC concentrations (e.g., gasoline bulk terminals, storage, etc.). Condensation is a separation technique in which one or more volatile compounds of vapor mixture are separated from remaining vapors through saturation followed by a phase change.

The reported efficiency is around 80%. Refrigerated condensers are used as air pollution control devices for treating emission streams with high VOC concentrations (usually > 5,000 ppmv). Removal efficiencies above 90% can be achieved with coolants such as chilled water, brine solutions, ammonia, special filter media, etc. depending upon the emission stream characteristics.

Thermal Oxidizer
Thermal oxidation systems operate in three (3) stages: a burner generates hot combustion gases, combustion products mix with the exhaust from the process lines, and the mixture is oxidized. Thermal incineration is performed at much higher temperatures than catalytic incineration, typically between 1200^{O}F and 2000^{O}F. Thermal incinerators operate at peak efficiency when oxidizing concentrated organic exhaust streams just above or below the upper and lower explosive limits. This is because the oxidation rate is directly proportional to the organic concentration, the local heat of reaction during oxidation, and the increased concentration of free radicals which participate in the oxidation reaction. Thermal oxidation destruction efficiency ranges from 95% to 99%.

Catalytic Thermal Oxidizer
This type of thermal oxidizer is a better system than the straight-shot thermal oxidizer. It uses a heated catalytic (platinum coated ceramic beads) system to destroy VOCs at a much lower temperature (around 650°F) and consumes less natural gas. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers require approximately 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate. Even though this type of control system can normally reach over 98% destruction efficiency, its catalytic media is very expensive to upkeep and has to be replaced every 5 years or so. It also has an odor problem due to the lower combustion temperature.

Carbon Adsorbers
Carbon adsorbers use activated carbon to remove VOC from low to medium concentration gas stream by adsorbtion. Adsorbtion itself is a phenomenon where gas molecules passing through a bed of solid particles (e.g., activated carbon) are selectively held there by attractive forces which are weaker and less specific than those of chemical bonds. During adsorbtion, a gas molecule migrates from the gas stream to the surface of the solid when it is held by physical attraction releases energy which typically equals or exceeds the heat of condensation. Most adsorbers can be cleaned by heating to a sufficiently high temperature, usually using steam or hot combustion gases or by lowering the pressure to a low value (vacuum). This cleaning process created a waste product, which will have to be properly disposed.

VOC and acid gases can be controlled with control efficiencies greater than 90%. Common problems with carbon adsorbers can be plugging and fouling of the activated carbon exposed to wet or heavily concentrated particulate gas streams. Sources may experience significant issues with maintenance and repair that result in unacceptable downtime for the control units.

Flare
Flaring is a combustion control process for VOC’s in which the waste gas stream is piped to remote, usually elevated, location (for safety reasons) and burned in an open flame in the open air using a specially designed burner tip, auxiliary fuel, and steam or air to promote mixing for nearly complete (>98%) VOC destruction. Complete combustion in VCU is governed by flame temperature, residence time in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation.

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable in reducing VOC emissions. All the control technologies listed in the step 1 are considered technically feasible options.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Control Option	Expected Control Efficiency
Flare	98%
Thermal Oxidation	98%
Condenser	98%
Carbon Adsorber	95%
Cooling and Condensing Systems	80%

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Naphtha loading operation and diesel loading operation*	*Loading flare (EU-4002)*	*98% CE* *naphtha: 0.049 lb/kgal* *diesel: 1.02E-03 lb/kgal* *Submerged loading*	
Countrymark	IN-0244 T103-35351-00011 (12/3//2015)	Truck Loading Rack	Flare vapor combustion unit, relief stack and vapor knockout box	35 mg/liter gasoline/ethanol loaded (equivalent to 0.292 lb VOC/kgal) 0.014 lb/kgal diesel loaded 0.016 lb/kgal kerosene loaded Leak Prevention measures (including submerged loading)	
Marathon	IN-0243 T129-34987-00005 (8/14/2015)	Truck Loading Rack	vapor recovery unit (VRU)	0.159 lb/kgal gasoline/ethanol loaded 0.014 lb/kgal diesel loaded Leak Prevention measures	
Countrymark	IN-0231 T055-35558-00003 (6/30/2015)	Truck loading rack	Flare vapor combustion unit, relief stack and vapor knockout box	VOC: 0.014 lb/kgal diesel loaded Leak prevention measures	

VOC limits for gasoline loading are not comparable to naphtha, which has a lower vapor pressure. Therefore the BACT for naphtha loading is established as the lb/kgal emission factor after control by a flare with DRE equal to 98% which is consistent with a flare operating in conformance with 40 CFR 60.18.
VOC limit of 0.014 lb/kgal is the most stringent for diesel loading. Therefore, it is chosen as BACT.

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Castleton Commodities (CCI)	TX-0756 116072, PSDTX1388 (6/22/2015)	Truck loading diesel	None	VOC: 1.99 lb/hr (4.53 tpy)	
Chevron Phillips	TX-0722 N178 (3/14/2014)	Loading - products vapor press < 0.5 psia	Submerged fill	0.01 lb/kgal	
Colonial Pipeline	NJ-0083 18046, BOP130002 (3/11/2014)	Loading rack - light products	VRU	40 CFR 63, Subpart R and 6B VOC: 0.42 lb/hr (1 mg/L) 95% CE	441.5 MMgal/yr
KM Liquids Terminals LLC	TX-0682 101199, N158 (6/12/2013)	Loading	VCU (If vapor pressure > 0.1 psia)	If vapor pressure > 0.1 psia, then vacuum loading rqd. Leak check 99.8% DRE (if vapor pressure >0.1 psia) 500 ppmv	
Transmontaigne	VA-0313 60242 (4/22/2010)	Loading rack - diesel	None	Only controls/limits when loading gasoline or ethanol	
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	loading rack	Vapor recovery system submerged fill	VOC: 1.7 ton/yr 0.01 lb/1000 gal diesel 0.06 lb/1000 gal naphtha 99.5% CE	172462496 gal/yr
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Chelsea Sandwich LLC	MA-0040 MBR-08-IND-007 (8/20/2008)	Loading rack - residual oil	RTO	VOC: 1.77 ton/mo (3.54 tpy) 90 % capture eff. and 99% destruction eff.	
Marathon Pipeline - Zachary Station	LA-0212 PSD-LA-721 (2/1/2007)	Loading Rack	Vapor combustor (products >1.5 psia)	VOC: 10 mg/L	

Riverview has proposed the use of a flare as BACT. A search of the RBLC shows that in addition to a flare, there are other types of control. A flare is considered top BACT for this type of operation.
IDEM is aware that that the above control technologies may be able to periodically achieve control efficiencies that exceed 98% under certain operating conditions (such as 99.8%). However, BACT must be achievable on a consistent basis under normal operational conditions. BACT limitations do not necessarily reflect the highest possible control efficiency achievable by the technology on which the emission limitation is based. The permitting authority has the discretion to base the emission limitation on a control efficiency that is somewhat lower than the optimal level. There are several reasons why the permitting authority might choose to do this. One reason is that the control efficiency achievable through the use of the technology may fluctuate, so that it would not always achieve its optimal control efficiency. In that case, setting the emission limitation to reflect the highest control efficiency would make violations of the permit unavoidable. To account for this possibility, a permitting authority must be allowed a certain degree of discretion to set the emission limitation at a level that does not necessarily reflect the highest possible control efficiency, but will allow the Permittee to achieve compliance consistently. While we recognize that greater than 98% may be achievable as an average during testing, IDEM allows for sources to include a safety factor, or margin of error, to allow for minor variations in the operation of the emission units and the control device.

Therefore, the proposed use of a flare with control of 98% is considered the top BACT for this operation.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

(a) The Product Loading Flare shall be designed and operated in accordance with 40 CFR 60.18.

(b) The Best Available Control Technology (PSD BACT) for VOC for the product loading rack shall be as follows:

  (1) The Product Loading Rack shall use only submerged loading.

  (2) The overall VOC control efficiency, including capture efficiency and destruction efficiency, for the Product Loading Flare shall be 98% or greater.

  (3) VOC emissions shall not exceed:

Emission Limitations	
Product	**lb/kgal**[1]
naphtha	0.049
Diesel	1.02E-03

Notes:
1. kgal = 1,000 gallons

VOC BACT Analysis
Residue Solidification Units

VCC Residue is the bottoms product of the VCC Vacuum Distillation Tower wherein Vacumm Gas Oil (VGO) is extracted for recycle. The residue is a heavy bitumen type flowable liquid at ~ 500 degree F with limited volatile organic content, i.e, sufficient only to enable pumping. A small amount of hydrocarbon is initially released. The potential VGO emissions are limited due to: 1) incorporation of VGO in the residue matrix, 2) initial quick cooling of the pastille bottom surface and hemi-spherical top surface, forming an initial hard coating and 3) reduction of VGO vapor pressure in the pastille and coating with travel along the cooling line. A limited volume of exhaust air flow is extracted from the front one-third portion of the enclosures to aid cooling.

Step 1: Identify Potential Control Technologies

Add-on controls:

There are two general categories of control methods for volatile organic compounds (VOCs): destruction methods and reclamation methods. Destruction control methods reduce the VOC concentration by high temperature oxidation into carbon dioxide and water vapor. Reclamation control methods consist of capturing VOCs for reuse or disposal. These are discussed in more detail below.

Destruction Control Methods
The destruction of organic compounds usually requires temperatures ranging from 1200°F to 2200°F for direct thermal oxidizers or 600°F to 1200°F for catalytic systems. Combustion temperature depends on the chemical composition and the desired destruction efficiency. Carbon dioxide and water vapor are the typical products of complete combustion. Turbulent mixing and combustion chamber retention times of 0.5 to 1.0 seconds are needed to obtain high destruction efficiencies.

Fume oxidizers typically need supplemental fuel. Concentrated VOC streams with high heat contents obviously require less supplementary fuel than more dilute streams. VOC streams sometimes have a heat content high enough to be self-sustaining, but a supplemental fuel-firing rate equal to about 5% of the total oxidizer heat input is usually needed to stabilize the burner flame. Natural gas is the most common fuel for VOC oxidizers, but fuel oil is an option in some circumstances.

Destruction control methods include:

(a) Thermal Oxidizer:

Thermal oxidation is the process of oxidizing VOC in a waste gas stream by raising the temperature above the VOC's auto-ignition point in the presence of oxygen for sufficient time to completely oxidize the organic contaminants to carbon dioxide and water. The residence time, temperature, flow velocity and mixing, and the oxygen concentration in the combustion chamber affect the oxidation rate and destruction efficiency. Thermal oxidizers operating costs are relatively high, since they typically require combustion of an auxiliary fuel (e.g., natural gas) to maintain combustion chamber temperature high enough to completely oxidize the contaminant gases. In general, thermal oxidizers are less efficient at treating waste gas streams with highly variable flowrates, since the variable flowrate results in varying residence times, combustion chamber temperature, and poor mixing. In addition, thermal oxidizers are also not generally cost-effective for low-concentration, high-flow organic vapor streams.

Thermal oxidizers can achieve 95-99.99+% VOC control efficiency and can be used over a wide range of organic vapor concentrations, but perform best at inlet concentrations of around 1,500-3,000 ppmv. Thermal oxidizers are typically designed to have a residence time of 0.3 to 1.0 second and combustion chamber temperatures between 1,200 and 2,000°F. In order to meet 98% or greater control or a 20 parts per million by volume (ppmv) compound exit concentration of non-halogenated organics, thermal oxidizers should typically be operated at a residence time of at least 0.75 seconds, a combustion chamber temperature of at least 1600°F, and with proper mixing. While thermal oxidation provides efficient VOC control, other pollutants such as nitrogen oxides and carbon monoxide are formed from the combustion process.

Thermal oxidizers are not generally recommended for controlling gases containing halogen- or sulfur-containing compounds, because of the formation of hydrogen chloride, hydrogen fluoride gas, sulfur dioxide, and other highly corrosive acid gases. It may be necessary to install a post-oxidation acid gas treatment system in such cases, depending on the outlet concentration. This would likely make incineration an uneconomical option. For halogenated VOC streams, a combustion temperature of 2000°F, a residence time of 1.0 second, and use of an acid gas scrubber on the outlet is recommended.

The three types of thermal oxidation systems include direct flame, recuperative, and regenerative thermal oxidizers, which are differentiated by the type of heat recovery equipment used.

(1) Direct Flame Thermal Oxidizer

A direct flame thermal oxidizer is comprised of a combustion chamber and does not include any heat recovery of exhaust air by a heat exchanger.

(2) Recuperative Thermal Oxidizer

A recuperative thermal oxidizer is comprised of the combustion chamber, a heat exchanger for preheating the untreated VOC gas stream, and, if cost-effective, a secondary energy recovery heat exchanger. In a recuperative thermal oxidizer, the untreated VOC gas stream entering the oxidizer is preheated using the heat content of the treated gas stream exiting the oxidizer using a heat exchanger, resulting in improved oxidizer efficiency and reduced auxiliary fuel usage. Recuperative thermal oxidizers usually are more economical than direct flame thermal oxidizers because they typically recover 40 to 70% of the waste heat from the exhaust gases.

(3) Regenerative Thermal Oxidizer

A regenerative thermal oxidizer typically consists of a set of 2 or 3 packed ceramic beds that are used to recover heat from hot combustion gases that are generated during combustion of the VOC gas stream and auxiliary fuel, resulting in improved oxidizer efficiency and reduced auxiliary fuel usage. An "inlet" bed is used to pre-heat the untreated VOC gas stream, an "outlet" bed is used to recover heat from the treated gas stream, and one bed is in a purge cycle. The purge cycle is needed to prevent emission spikes each time the gas flow is redirected. The oxidizer is operated on a rotating schedule, where the gas flow through the ceramic beds is redirected periodically using a set of gas flow dampers. Once the heat energy of the "inlet" ceramic bed has been depleted, the flow through the system is redirected so that the untreated VOC gas stream entering the oxidizer is directed through the previously heated "outlet" ceramic bed. Regenerative thermal oxidizers have much higher heat recovery efficiencies than recuperative thermal oxidizers, recovering 85 to 95% of the heat from the treated gas stream, and therefore have lower auxiliary fuel requirements. However, compared to direct flame and recuperative thermal oxidizers, regenerative thermal oxidizers typically have higher capital (equipment and installation) costs, are larger and heavier, and have higher maintenance costs.

(b) Catalytic Oxidizer:

Catalytic oxidation is the process of oxidizing organic contaminants in a waste gas stream within a heated chamber containing a catalyst bed in the presence of oxygen for sufficient time to completely oxidize the organic contaminants to carbon dioxide and water. The catalyst is used to lower the activation energy of the oxidation reaction, enabling the oxidation to occur at lower reaction temperatures compared to thermal oxidizers. The residence time, temperature, flow velocity and mixing, the oxygen concentration, and type of catalyst used in the combustion chamber affect the oxidation rate and destruction efficiency. Catalytic oxidizers typically require combustion of an auxiliary fuel (e.g., natural gas) to maintain combustion chamber temperature high enough to completely oxidize the contaminant gases. Catalytic oxidizers operate at lower temperatures and require less fuel than thermal oxidizers, they have a smaller footprint, and they need little or no insulation. The catalyst bed is usually composed of the following: (1) the substrate, typically ceramic or metal honeycombs, grids, mesh pads, or beads; (2) the carrier, a high surface area inorganic material such as alumina that is bonded to the substrate that contains a complex pore structure; and (3) the catalyst, a thin layer of material deposited onto the carrier. The most widely used catalysts for VOC oxidation are noble metals, such as platinum, palladium and rhodium or mixtures thereof. Base metal catalysts, such as oxides of chromium, cobalt, copper, manganese, titanium, and vanadium may also be used for VOC oxidation. Similar to thermal oxidizers, catalytic oxidizers may use regenerative or recuperative heat recovery to reduce auxiliary fuel requirements, where the untreated VOC gas stream entering the catalytic oxidizer is preheated using the heat content of the treated gas stream exiting the catalytic oxidizer.

Catalytic oxidizers can achieve 90-99% VOC control efficiency, depending on the oxidizer design and waste stream characteristics. Catalytic oxidizers are typically designed to have a residence time of 0.5 seconds or less and combustion chamber temperatures between 600 and 1,200°F. Catalytic oxidation is most suited to waste gas streams with little variation in the flow rate and type and concentration of VOC to be treated. In addition, catalytic oxidizers should not be used for waste gas streams that have a high concentration of particles, silicone, sulfur, halogen compounds, and/or heavy hydrocarbons that can cause fouling or masking of the catalyst, and for waste gas streams that contain metals such as mercury, phosphorus, arsenic, antimony, bismuth, lead, zinc, and/or tin that can cause catalyst poisoning.

(c) Flare:

Flaring is the process of oxidizing VOC in a waste gas stream by piping the waste gas to a remote, usually elevated location and burning it in a flame using a specially designed burner tip, auxiliary fuel, and steam or air to promote mixing. Flares are generally categorized in two ways: (1) by the height of the flare tip (i.e., ground or elevated), and (2) by the method of enhancing mixing at the flare tip (i.e., steam-assisted, air-assisted, pressure-assisted, or non-assisted). Flares can be used to control almost any VOC stream, and can typically handle large fluctuations in VOC concentration, flow rate, heating value, and inert species content. Flaring is appropriate for continuous, batch, and variable flow vent stream applications, but the primary use is that of a safety device used to control a large volume of pollutant resulting from upset conditions. Flares have primarily been used in petroleum production, petroleum refineries, and chemical plants to control waste gas streams containing low molecular weight VOC with high heating values.

A properly operated flare can achieve 98+% VOC control efficiency when controlling emission streams with heat contents greater than 300 British thermal units per standard cubic foot (Btu/scf). If the waste gas stream has a heat content less than 300 Btu/scf, auxiliary fuel must be introduced in sufficient quantity to make up the difference. The VOC destruction efficiency of a flare depends upon the waste gas characteristics (density, flammability, heating value, and VOC component autoignition temperatures) and the combustion zone conditions (temperature, residence time, mixing, and available oxygen). While flares can provide efficient VOC control, other pollutants such as nitrogen oxides (NOx) and carbon monoxide (CO) are formed from the combustion process. Flares are not generally recommended for controlling gases containing halogen- or sulfur-containing compounds, because of the formation of hydrogen chloride, hydrogen fluoride gas, sulfur dioxide, and other highly corrosive acid gases.

Reclamation Control Methods

Organic compounds may be reclaimed by one of three possible methods: adsorption, absorption (scrubbing), or condensation. In general, the organic compounds are separated from the emission stream and reclaimed for reuse or disposal. Depending on the nature of the contaminant and the inlet concentration of the emission stream, recovery technologies can reach efficiencies of 98%.

(d) Carbon Adsorption Unit:

Carbon adsorption is a process where VOCs are removed from a waste gas stream when it is passed through a bed containing activated carbon particles, which have a highly porous structure with a large surface-to-volume ratio. Carbon adsorption systems usually operate in two phases: adsorption and desorption. During adsorption, the majority of the VOC molecules migrate from the gas stream to the surface of the activated carbon (through the activated carbon pores) where it is lightly held to the surface by weak intermolecular forces known as van der Waals' forces. As the activated carbon bed approaches saturation with VOC, its control efficiency drops, and the bed must be taken offline to be replaced or regenerated. Typically, two activated carbon beds are utilized on a rotating schedule, where a second bed (containing fresh or previously regenerated activated carbon) is brought online to continue controlling the VOC gas stream while the first bed is being replaced or regenerated. In regenerative systems, most VOC gases can be desorbed and removed from the activated carbon bed by heating the bed to a sufficiently high temperature, usually via steam or hot air, or by reducing the pressure within the bed to a sufficiently low value (vacuum desorption). The regenerated activated carbon can be reused and the VOCs that are removed from the bed can be reclaimed or destroyed.

Carbon adsorber size and purchase cost depend primarily on the gas stream volumetric flow rate, temperature, pressure, VOC composition, VOC mass loading, and moisture and particulate contents. The adsorptive capacity of an activated carbon bed for a VOC gas tends to increase with the VOC gas phase concentration, molecular weight, diffusivity, polarity, and boiling point. Carbon adsorption systems can be used for VOC gas concentrations from less than 10 ppm to approximately 10,000 ppm. Carbon adsorption systems (in general) are usually limited to waste gas streams with VOC compounds having a molecular weight of more than 50 and less than approximately 200 lb/lb-mole, since low molecular weight organics usually do not adsorb sufficiently and high molecular weight compounds are difficult to desorb and remove during the desorption cycle. Industrial applications of adsorption systems include control for dry cleaning, degreasing, paint spraying, solvent extraction, metal foil coating, paper coating, plastic film coating, printing, pharmaceuticals, rubber, linoleum, and transparent wrapping.

Carbon adsorption systems can achieve 95-99% VOC control efficiency. Carbon adsorption system control efficiency increases with reduced VOC gas stream temperatures. Therefore, high temperature VOC gas streams are typically cooled prior to entry into the activated carbon bed. Particulate matter and high moisture concentrations present in the gas stream compete with the VOC for pore space within the activated carbon and thereby reduce the VOC adsorptive capacity and control efficiency of the carbon adsorption systems. In addition, particulate matter and moisture can become entrained within the carbon bed, causing operating problems such as increased pressure drop across the bed.

(e) Gas Absorption (wet scrubber):

A wet scrubber is an absorption system in which a waste gas stream is interacted with a scrubbing fluid inside a contact chamber in order to strip particulate or gaseous pollutants from the waste gas stream through the processes of diffusion and dissolution. In many cases, an additive such as an acid, a base, or a VOC oxidizing agent is dissolved in the scrubbing fluid so that the dissolved gaseous pollutant chemically reacts with the scrubbing fluid to form a non-volatile or soluble product, thereby allowing additional gaseous pollutant to be absorbed by the scrubbing fluid. The four types of wet scrubber systems include packed towers, plate (or tray) columns, venturi scrubbers, and spray chambers. Gas and liquid flow through an absorber may be countercurrent, crosscurrent, or cocurrent. When used as an emission control technique, wet scrubbers are typically used for controlling particulate, acid gases, halogen gases, and highly soluble gases such as sulfur dioxide and ammonia.

If a wet scrubber is used for VOC control, the scrubbing fluid chosen should have a high solubility for the VOC gas, a low vapor pressure, a low viscosity, and should be relatively inexpensive. Water is the most commonly used scrubbing fluid for absorbing highly water-soluble (hydrophilic) VOC compounds such as methanol, ethanol, isopropanol, butanol, acetone, and formaldehyde. Other scrubbing fluid such as mineral oils, nonvolatile hydrocarbon oils, and aqueous solutions containing surfactants or amphiphilic block copolymers may be used for absorbing water-insoluble (hydrophobic) VOC compounds. Physical absorption is typically enhanced by lower temperatures, greater scrubbing fluid contacting time and surface area, higher scrubbing fluid to VOC ratio, and higher VOC concentrations in the gas stream.

Wet scrubber systems can achieve 70-99% VOC control efficiency, depending on the VOC solubility in the scrubbing fluid, the VOC-scrubbing fluid temperature, the scrubbing fluid contacting time and surface area, the scrubbing fluid to VOC ratio, the VOC concentration in the gas stream, and whether the scrubbing fluid contains a VOC oxidizing agent. Wet scrubber absorption system control efficiency increases with reduced VOC gas stream temperatures. Therefore, high temperature VOC gas streams are typically cooled prior to entry into the wet scrubber. When used to control VOC, the spent scrubbing fluid must be regenerated, treated, or shipped offsite for proper disposal.

(f) Condensation Unit:

Condensation is the separation of VOCs from an emission stream through a phase change, by either increasing the system pressure or, more commonly, lowering the system temperature below the dew point of the VOC vapor. Three types of condensers are used for air pollution Controls: (1) conventional non-refrigeration systems (such as cold-water direct contact condensers similar to wet scrubbers and cold-water indirect heat exchangers); (2) refrigeration systems (including mechanical compression refrigeration using chlorofluorocarbons (CFCs) and hydrofluorocarbons (HFCs) and Reverse Brayton Cycle refrigeration); and (3) cryogenic systems that utilize liquid nitrogen (including direct contact condensers and indirect heat exchangers).

Condensation units control VOC more efficiently when they are used for gas streams containing high concentrations of VOC and with low exhaust volumes. Condensation units are typically utilized at sources where there is a significant cost benefit to recovering the organic liquid for reuse, where the recovered organic liquids do not contain multiple organic compounds or water that require separation, and where the heat content of gas stream will not overload the refrigeration system. In addition, condensation units are typically used only on gas streams that have little or no particulate contamination, which can cause fouling within the condensation equipment and reduced heat transfer efficiency. Some industrial applications where refrigerated condensers are used include the dry cleaning industry, degreasers using VOC or halogenated solvents, transfer of volatile organic liquid or petroleum products, and vapors from storage vessels.

Cold-water (non-refrigeration) condensation systems can achieve 90-99% VOC control efficiency, depending on the vapor pressures of the specific compounds. Condensation units using mechanical compression refrigeration (using CFC or HFC) can achieve 90+% VOC control efficiency, condensation units using Reverse Brayton Cycle refrigeration can achieve 98% VOC control efficiency, and condensation units using cryogenic (liquid nitrogen) cooling can achieve 99+% VOC control efficiency.

Other Control Methods

(g) Bio-filtration is a process in which a waste gas stream is passed through a bed of peat, compost, bark, soil, gravel, or other inorganic media in order to strip organic contaminant gases from the waste gas stream through the process of dissolution in the bed moisture and adsorption to the bed media. Under aerobic conditions, microorganisms naturally present in the bed oxidize the organic contaminant gases within the bed to carbon dioxide, water, and additional biomass through metabolic processes. If the temperature of the waste gas stream is too high, the gas stream must be cooled to an optimum temperature before it can be treated in the biofilter in order to maintain the viability of the microorganisms. In addition, the bed must be monitored and maintained at an optimum moisture content and pH in order to prevent cracking of the bed media and to maintain the viability of the microorganisms.

Bio-filtration systems are designed to follow three basic steps. First, a pollutant in the gas phase is passed through a biologically active packed bed. The pollutant then diffuses into the biofilm immobilized on the packing medium. Finally, microorganisms growing in the biofilm oxidize the pollutant as a primary substrate or co-metabolite and in the process convert contaminants into the benign end products of carbon dioxide, water and additional biomass.

Three primary bioreactor configurations are available to treat stationary sources of air pollution: bio-filters, bio-trickling filters, and bio-scrubbers.

(1) Bio-Filters

Bio-filters are the simplest and oldest of the three vapor-phase bioreactors and involve passing a contaminated air stream through a reactor containing biologically-active packing material. The contaminants are transferred from the air stream into a bio-film immobilized on the support media and are converted by the microorganisms into CO2, water, and additional biomass. Moister is typically supplied to the bio-film in a humid inlet waste gas stream. Packing media used in bio-filter beds can be broadly categorized as either "natural" or "synthetic". Natural media include wood chips, peat, and compost, with compost by far the most widely used. Synthetic media include activated carbon, ceramic pellets, polystyrene beads, ground tires, plastic media, and polyurethane foam. Natural organic packing media generally contain a supply of nutrients as a naturally occurring component of the packing itself. When a synthetic support medium is used, nutrients must be added for microbial growth.

(2) Bio-Trickling Filters

Bio-trickling filters are similar to bio-filters with the exception that there is a liquid nutrient medium continuously recalculating through the column. To facilitate the recirculation of the liquid phase, rigid synthetic media is used as the packing medium. Microorganisms grow primarily as a fixed film on inert packing media but may also be present in the liquid phase because they can both grow suspended in the liquid phase and because the flowing liquid imparts sufficient force to detach biomass from the solid support media. Contaminants are transferred from the air stream into the liquid phase and bio-film for subsequent degradation.

Potential disadvantages of bio-trickling filter operations include: clogging of the pore space if the filter is treating high VOC loads or if the filter is provided excess nutrients, and the need to manage the liquid stream. An additional disadvantage is that bio-trickling filters may have more difficulty treating poorly soluble compounds since the specific surface are in bio-tricking filters is generally lower.

(3) Bio-Scrubbers

Bio-scrubbers combine physical and chemical treatment with a biological treatment in two separate reactors. In the first reactor, the contaminated air stream is contacted with water in a reactor packed with inert media, resulting in contaminant transfer from the air phase to the liquid phase. The liquid is then directed into an activated sludge reactor where the contaminants are biologically degraded. The separated activated sludge tank allows the reactor to treat higher concentrations of compounds than bio-filters can handle. In addition since compound transfer and degradation occur in separate reactors, optimization of each reactor can take place separately. As with bio-trickling filters, bio-scrubbers offer greater operator control over nutrient supply, acidity, and the build-up of toxic by-products.

A potential disadvantage of bio-scrubbers is that slower growing microorganisms may be washed out of the system and disposal of excess sludge is required.

Step 2: Eliminate Technically Infeasible Options

There are some add-on control devices that are considered technically feasible, however, due to the relatively low PTE of VOC for each unit, there are no add-on control devices that are considered economically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no technically feasible control options.

Step 4: Evaluate the Most Effective Controls and Document the Results

A search in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) did not produce any results for this type of unit.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

BACT shall be the following:

(a) VOC emissions from residue solidification unit EU-5001a-5001d (stack S-5001) shall not exceed 1.40 lb/hr.

(b) VOC emissions from residue solidification unit EU-5002a-5002d (stack S-5002) shall not exceed 1.40 lb/hr.

(c) VOC emissions from residue solidification unit EU-5003a-5003d (stack S-5003) shall not exceed 1.40 lb/hr.

(d) VOC emissions from residue solidification unit EU-5004a-5004d (stack S-5004) shall not exceed 1.40 lb/hr.

Particulate (PM, PM_{10} and $PM_{2.5}$) BACT Analysis
Cooling Tower

Step 1: Identify Potential Control Technologies

PM emissions from cooling towers are typically controlled through one of the following mechanisms:

(1) Drift eliminators.
(2) Minimizing total dissolved solids (TDS).

Step 2: Eliminate Technically Infeasible Options:

For the cooling tower, the above listed control technologies are considered technically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The control technologies for cooling towers are ranked as follows:

(1) Drift eliminators.
(2) Minimization of total dissolved solids (TDS).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following tables summarize other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Cooling Tower

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*3 Cell Cooling Tower*	*Drift Eliminator*	*PM/PM10/PM2.5: 0.0005% drift 2,395 mg/l TDS VOC: 1.34 lb/hr*	*10,667 GPM, each*
South Louisiana Methanol LP	LA-0312 PSD-LA-780(M1) (6/30/2017) (draft)	ECT-14 - Econamine Cooling tower (EQT0018)	HE drift eliminators 0.0005% drift 2,660 ppm TDS	PM10: 0.44 tpy	29,120 gpm (ea of 3 cells)
				PM2.5: 0.01 tpy	
		CT-13 - cooling tower (EQT0007)		PM10: 0.96 lb/hr 3.50 tpy	231,000 gpm (each of 18 cells)
				PM2.5: 0.01 lb/hr 0.02 tpy	
Indorama Ventures Olefins Inc	LA-0314 PSD-LA-813 (8/3/2016)	cooling towers - 007	drift eliminators	PM10/PM2.5: 0.0005% drift 1400 ppm tds	86,500 gpm
			monitoring req'd by 40 CFR 63, subpart XX	VOC, no limit	
Lake Charles Methanol LLC	LA-0305 PSD-LA-803(M1) (6/30/2016)	cooling towers: unit A	drift eliminators	PM10/PM2.5: 0.0005% drift	241,843 gpm
		cooling towers: unit B			201,196 gpm
		cooling towers: unit C			72,531 gpm
PM/PM10/PM2.5 requirement of 0.0005% drift is determined to be BACT. Specification of circulating water TDS are not applied consistently and TDS may vary with water supply characteristics tower cycles of concentration, so the TDS limitation is chosen as a worst case for cooling tower operations.					
Exxon Mobil Oil Corp	TX-0832 PSDTX768M1, PSDTX799, PSDTX802 (1/9/2018) (draft)	cooling towers	drift eliminators	PM/PM10/PM2.5 control, no limit	-
Total Petrochemicals & Refining USA, Inc	TX-0815 122353, PSDTX1426, GHGPSDTX114, (1/17/2017)	cooling tower	drift eliminator	PM10 control, no limit	-
			cooling water VOC concentration non-contact	27.9 tpy	
Methanex USA LLC	LA-0317 PSD-LA-761(M4) (12/22/2016)	cooling towers (I-CT-621, II-CT-621)	drift eliminators	PM10/PM2.5: 0.001% drift	66,000 gpm (ea)
Sasol Chemicals (USA) Inc	LA-0319 PSD-LA-814 (9/1/2016)	cooling tower y12-800	complying with 40 CFR 63.104	VOC, no limit	-
	LA-0288 PSD-LA-778 (5/23/2014)	ASU cooling tower (EQT 636)	HE drift eliminators and low TDS water	PM10/PM2.5: 7.4 tpy 0.001% drift 1708 mg/l TDS (ann avg)	197,689 gpm
		process cooling towers (EQT 634 &635)		PM10/PM2.5: 6.99 tpy 0.001% drift 1724 mg/l TDS (ann avg)	184,920 gpm, ea
	The GTL project was reportedly cancelled in November 2017, therefore this entry is not considered to represent BACT for the proposed source.				
	LA-0301 PSD-LA-779 (5/23/2014)	cooling tower (EQT 979)	weekly TDS measurement, avg TDS w/ mfr's drift rate and design	PM10/PM2.5: 20.47 tpy	358,000 gpm

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
	LA-0302 PSD-LA-779 (5/23/2014)	cooling tower (EQT 1011)	circ to calculate emissions	PM10/PM2.5: 1.71 tpy	156,000 gpm
Equistar Chemicals LP	LA-0295 PSD-LA-806 (7/12/2016)	CGP unit cooling tower (3-03, EQT 15)	monthly monitoring	VOC: 0.13 lb/hr (included in combined cooling tower cap of 12.29 tpy)	3,000 gpm
Flint Hills Resources Houston Chemical LLC	TX-0803 18999, PSDTX755M1, N216 (7/12/2016)	cooling tower	drift eliminators	PM10/PM2.5: 0.001% drift	-
	TX-0801 GHGPSDTX137 (6/24/2016)		design value	CO2e: 0.005% drift	
Flopam Inc	LA-0318 PSD-LA-747(M5) (1/7/2016)	cooling towers	integrated drift eliminators	PM10, no limit	-
Ticona Polymers Inc	TX-0774 123316, PSDTX1438, GHGPSDTX (11/12/2015)	cooling tower	drift eliminators meeting 0.001% drift	PM10: 3.07 tpy	10,400 (presumed gpm)
				PM2.5: 0.01 tpy	
			minimize VOC leaks into cooling water	VOC: 3.64 tpy	
			minimize methane leaks into cooling tower	CO2e: 420 tpy	
The Dow Chemicals Co	TX-0754 100787, PSDTX1314M1 (7/10/2015)	cooling tower	non-contact design, drift eliminators meeting 0.005%	VOC: 0.05ppm in return to tower	75,000 gpm
Castleton Commodities Int'l Corpus Christie	TX-0756 116072, PSDTX1388 (6/19/2015)	cooling tower	no contact, low drift	VOC: 0.6 lb/hr 2.63 tpy	15,000 gpm
Phillips 66 Co	IL-0115 06050052 (1/23/2015)	cooling water tower (CWT-26)	drift eliminators and monitoring program	VOC: 0.005% (12 mo total) 1.10 tpy (12 mo total)	12,000 gpm
Formosa Plastics Corporation	TX-0703 107520, PSDTX1384 (8/4/2014)	Cooling Tower	Drift Eliminator	PM2.5: 0.001% Drift	-
			monthly VOC monitoring by TCEQ El Paso method)	VOC: no limits	
C3 Petrochemicals LLC	TX-0744 PSD-TX-1342-GHG (6/12/2014)	Cooling Tower	-	CO2e	-
Natgasoline LLC	TX-0657 107764, PSDTX1340 (5/16/2014)	Cooling Tower	Monthly monitoring VOC	VOC: 0.08 ppmw and 3.3 tpy	99 MG/yr
			Drift Eliminator, 0.001% drift	PM: 82.57 tpy	
				PM10: 1.28 tpy	
				PM2.5: 0.03 tpy	
Formosa Plastics Corporation	TX-0703 107520, PSDTX1384 (8/4/2014)	Cooling Tower	Drift Eliminator	PM2.5: 0.001% Drift	-

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Big Lake Fuels LLC	LA-0315 PSD-LA-781 (5/23/2014) (draft)	cooling tower	HE drift eliminator	PM10: 0.39 lb/hr 1.73 tpy	6,472,902 gpm
				PM2.5: 0.24 lb/hr 1.04 tpy	
			monthly VOC monitoring	VOC: 4.53 lb/hr 19.85 tpy	
Emberclear GTL MS LLC	MS-0092 0040-00055 (5/8/2014)	cooling tower, induced draft	HE drift eliminator	PM/PM10/PM2.5: 0.001% drift	1,420 gpm
			monthly strippable VOC monitoring, modified El Paso method	VOC: 0.70 lb VOC/MMgal (12 mo avg)	
Valero Refining New Orleans LLC	LA-0246 PSD-LA-619(M6) (12/31/2010)	EQT0010 - Cooling Tower 403	Monitoring VOC concentration	VOC: 76.0 lb/hr	61,250 gpm
			Drift Eliminator	PM10: 1.2 lb/hr	
		EQT0244 - New West Cooling Tower	Monitoring VOC concentration	VOC: 49.63 lb/hr	40,000 gpm
			Drift Eliminator	PM10: 0.08 lb/hr	
		EQT0035 - cooling tower CT-600	Monitoring VOC concentration	VOC: 55.84 lb/hr	45,000 gpm
			Drift Eliminator	PM10: 0.09 lb/hr	
		EQT0243 - HCU cooling tower	Monitoring VOC concentration	VOC: 62.04 lb/hr	50,000 gpm
			Drift Eliminator	PM10: 0.10 lb/hr	
Sabina Petrochemicals LLC	TX-0575 41945, N018M1 (8/20/2010)	Cooling Tower	noncontact design, Monthly monitoring of VOC (El Paso method)	VOC: 13.4 tpy	73,000 gpm

Step 5: Select BACT

IDEM, OAQ has established BACT for the cooling towers as:

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

(a) PM, PM10, and PM2.5 emissions from the cooling tower (EU-6001, EU-6002 and EU-6003) shall be controlled by the use of drift eliminators with a maximum drift rate of no more than 0.0005%.

(b) Total dissolved solids (TDS) in the circulating cooling water shall not exceed 2,395 mg/l.

(c) VOC emissions from the cooling towers (EU-6001, EU-6002 and EU-6003) shall not exceed 1.34 lb/hr.

BACT Analysis
Emergency Generators - PM/PM10/PM2.5, NOx, SO2, VOC, CO and CO2e

Step 1: Identify Potential Control Technologies

PM/PM10/PM2.5, NOx, SO2, VOC, CO and CO2e emissions can be controlled with the following control technologies:

(1) Good Combustion Practices
(2) Low sulfur diesel

Step 2: Eliminate Technically Infeasible Options

Good Combustion Practices is the only technically feasible option.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Emergency Generators

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (hp)
Riverview Energy	*Proposed*	*Emergency Diesel Generator*	*Good combustion practices*	*PM/PM10/PM2.5: 0.20 g/kW-hr SO2: 15 ppm S in fuel NOx + NMHC: 6.40 g/kW-hr CO: 3.50 g/kW-hr CO2e: 811 tons per 12-month consecutive period*	2,800
		Emergency Diesel Fire Pump	*Good combustion practices*	*PM/PM10/PM2.5: 0.20 g/kW-hr SO2: 15 ppm S in fuel NOx+NMHC: 4.00 g/kW-hr CO: 3.50 g/kW-hr CO2e: 217 tons per 12-month consecutive period*	750
Standards applicable to stationary RICE are highly variable, depending on model year, power output, and service category. In general, the requirements of the NSPS, 40 CFR 60, Subpart IIII are recognized as the most restrictive limitations for new compression ignition stationary RICE.					
Florida Power & Light	FL-0356 (3/9/2016)	ULSD Emergency generators	ULSD	BACT limits equal to NSPS Subpart IIII limits. Will use IIII certified engine. CO: 3.5 g/KW-hr PM: 0.2 g/KW-hr SO2: 0.0015% S in ULSD	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (hp)
		Diesel-Fired Emergency Fire pump engine	ULSD	BACT limits equal to NSPS Subpart IIII limits. Will use IIII certified engine. CO: 3.5 g/KW-hr PM: 0.2 g/KW-hr 0.0015% S in ULSD	
Grain Processing Corp.	IN-0234 (12/8/2015)	Diesel-Fired Emergency Fire pump engine	Good combustion practices	1,128 gallons diesel/yr CO: 2.01 g/hp-hr PM/PM10/PM2.5: 0.16 g/hp-hr NOx: 9.5 g/hp-hr 0.0015% S in ULSD VOC: 0.05 g/hp-hr	425 hp
Mattawoman Energy	MD-0045 (11/13/2015)	Diesel-fired emergency generator	Good combustion practices and ULSD	40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ CO: 3.5 g/KW-hr (converts to 2.63 g/hp-hr) PM: 0.2 g/KW-hr (converts to 0.15 g/hp-hr) PM10/PM2.5: 0.18 g/hp-hr NOx: 6.4 g/KW-hr (converts to 4.8 g/hp-hr) Sulfuric Acid Mist: 0.007 g/hp-hr	
Corrigan OSB	TX-0770 (10/23/2015)	Diesel-Fired Emergency Fire pump engine	Good combustion practices with clean burning fuel and limited operating hours	CO: 0.06 tpy CO2e: 335 tpy	1.4 MMBtu/hr
Florida Power & Light	FL-0354 (8/25/2015)	Diesel-Fired Emergency Fire pump engine	ULSD	BACT limits equal to NSPS Subpart IIII limits. CO: 3.5 g/KW-hr (converts to 2.63 g/hp-hr) PM: 0.2 g/KW-hr (converts to 0.15 g/hp-hr) NOx: 4.0 g/kw-hr (converts to 3.0 g/hp-hr) 0.0015% S in ULSD	29 MMBtu/hr (300 hp)
BASF	TX-0728 (4/1/2015)	emergency diesel generator	Hours of operation (52 hr/yr non-emergency) Tier II engine	NSPS & NESHAP CO: 0.2 tpy (0.0126 g/hp-hr) NOx: 0.35 tpy (0.0218 g/hp-hr) LAER PM10/PM2.5: 0.15 lb/hr (0.01 tpy) VOC: 0.7 lb/hr 0.02 tpy	1500
			This plant has not yet begun operation. Therefore, compliance with these limits has not been demonstrated.	SO2: 0.61 lb/hr (0.02 tpy)	
			ULSD (15 ppmw)		

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (hp)
Tinker AFB	OK-0164 (1/8/2015)	Diesel-Fired Emergency Fire pump engine	ULSD and Good combustion practices	100 hr/yr operation VOC: 0.15 g/hp-hr CO2e: 44.0 tpy	
Moundsville Power	WV-0025 (11/21/2014)	Diesel-fired emergency generator	None	CO: 2.6 g/hp-hr PM2.5: 0.15 g/hp-hr NOx: 4.8 g/hp-hr NMHC+NOx VOC: 1.24 lb/hr	2015.7 hp
		Fire Pump Engine	None	Limited to 100 Hours/year CO: 1.44 lb/hr PM2.5: 0.15 g/hp-hr NOx: 3.0 g/hp-hr NMHC+NOx VOC: 0.17 lb/hr CO2e: 309.0 lb/hr	251 hp
BP Amoco Chemical	SC-0170 (11/7/2014)	Emergency generator	ULSD	100 hr/yr non-emergency use, tier 3 emission standards	
Keys Energy Center	MD-0046 (10/31/2014)	Fire Pump Engine	Good combustion practices and ULSD	NSPS IIII CO: 3.5 g/kw-hr PM: 0.2 g/kw-hr PM10: 0.18 g/kw-hr NOx: 4.0 g/kw-hr	300 hp
Adarko Petroleum Corp.	FL-0347 (9/16/2014)	emergency diesel generator	Use of good combustion practices based on the most recent manufacturer's specifications	No limits listed	3300
Cronus Chemicals	IL-0114 (9/5/2014)	Emergency generator	ULSD	PM/ PM10/PM2.5: 0.1 g/KW-hr NOx: 0.67 g/KW-hr VOC: 0.4 g/KW-hr (converts to 0.3 g/hp-hr) CO: 3.5 g/KW-hr	
These limits cite Tier 4 standards for nonroad engines in model year 2014 and earlier (40 CFR 1039.102, Table 7). This reference is not considered applicable to new engines proposed for Riverview Energy Corp. The definition of nonroad engine in part 1039 excludes stationary engines, and the emission standards in that part are not applicable unless referenced in another part.					
Formosa Plastics	TX-0703 (8/8/2014)	Emergency generators	Good combustion	40 CFR 60 Subpart IIII requirements 40 CFR 80.510	
Nucor Steel	AL-0301 (7/22/2014)	Diesel-fired emergency generator	None	CO: 0.0055 lb/hp-hr (converts to 2.5 g/hp-hr) PM: 0.0007 lb/hp-hr (converts to 0.32 g/hp-hr) NOx: 0.015 lb/hp-hr (converts to 6.8 g/hp-hr)	
Nucor Steel	AL-0275 (7/22/2014)	Diesel-fired emergency generator	None	CO: 0.0055 lb/hp-hr (converts to 2.5 g/hp-hr) PM: 0.0007 lb/hp-hr (converts to 0.32 g/hp-hr) NOx: 0.015 lb/hp-hr (converts to 6.8 g/hp-hr)	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (hp)
Constellation Power	MD-0043 (7/1/2014)	Emergency generator	Good combustion practices	40 CFR 60 Subpart IIII requirements ULSD, limited hours PM: 0.15 g/hp-hr PM10/PM2.5: 0.17 g/hp-hr NOx: 4.8 g/hp-hr & 6.4 g/kw-hr	
Dominion Cove Point Terminal	MD-0044 (6/9/2014)	Emergency generator	Good combustion practices	40 CFR 60 Subpart III requirements ULSD CO: 2.6 g/hp-hr & 3.49 g/kw-hr PM: 0.15 g/hp-hr & 0.2 kw-hr PM10/PM2.5: 0.17 g/hp-hr & 0.23 g/kw-hr NOx (LAER): 4.8 g/hp-hr & 6.4 g/kw-hr VOC (LAER): 4.8 g/hp-hr & 6.4 g/kw-hr	
Midwest Fertilizer	IN-0173 (6/4/2014)	diesel-fired emergency generator	Good combustion practices and energy efficiency	hours of operation <500 hr/yr PM/PM10/PM2.5: 0.15 g/hp-hr NOx: 4.46 g/hp-hr CO: 2.61 g/hp-hr VOC: 0.31 g/hp-hr GHG: 526.39 g/hp-hr	
		Diesel-Fired Emergency Firewater Pump	Good combustion practices and energy efficiency	hours of operation <500 hr/yr PM/PM10/PM2.5: 0.15 g/hp-hr NOx: 2.83 g/hp-hr CO: 2.60 g/hp-hr VOC: 0.141 g/hp-hr GHG: 527.4 g/hp-hr	
Mag Pellet	IN-0185 (4/24/2014)	Diesel fire pump	Good combustion practices	500 hr/yr PM/PM10/PM2.5: 0.15 g/hp-hr NOx: 3.0 g/hp-hr SO2: 0.29 lb/MMBtu CO2e: 31.11	
Ohio Valley Resources	IN-0179 (9/25/2013)	Diesel-fired emergency generator	Good combustion practices	hours of operation <200 hr/yr PM/PM10/PM2.5: 0.15 g/hp-hr NOx: 4.46 g/hp-hr CO: 2.61 g/hp-hr VOC: 0.31 g/hp-hr GHG: 526.39 g/hp-hr	
		Diesel-Fired Emergency Firewater Pump	Good combustion practices	hours of operation <200 hr/yr PM/PM10/PM2.5: 0.15 g/hp-hr NOx: 2.86 g/hp-hr CO: 2.60 g/hp-hr VOC: 0.141 g/hp-hr GHG: 527.4 g/hp-hr	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (hp)
DynoNobel Louisiana Ammonia	LA-0272 (3/27/2013)	emergency diesel generator	500 hr/yr limit Energy efficiency measures good combustion practices	Comply with 40 CFR 60, Subpart IIII	1200
				CO: 3.5 g/Kw-hr (2.6 g/hp-hr)	
				NOx: 6.4 g/Kw-hr (4.77 g/hp-hr)	
				PM10/PM2.5: 0.2 g/Kw-hr (0.15 g/hp-hr)	
				VOC: 6.4 g/Kw-hr (4.77 g/hp-hr)	
				CO2e: energy efficiency	
St. Joseph Energy Center	IN-0158 (12/3/2012)	emergency diesel generators (3)	Good engineering design and fuel efficient design post combustion carbon control	CO2e: 1186 tpy (combined)	2012 and 2 @ 1006
			Combustion design controls and 500 hr/yr (each)	CO: 2.6 g/hp-hr NOx: 4.8 g/hp-hr PM/ PM10/PM2.5: 0.15 g/hp-hr	
			ULSD and 500 hr/yr (each)	SO2: 0.012 lb/hr VOC: 1.04 lb/hr	
		firewater pump diesel engines (2)	Good engineering design and fuel efficient design	CO2e: 172 tpy (combined)	371 (each)
			Combustion design controls and 500 hr/yr (each)	CO: 2.6 g/hp-hr NOx: 3.0 g/hp-hr PM/ PM10/PM2.5: 0.15 g/hp-hr	
Indiana Gasification - IN	IN-0166 / T147-30464-00060 (6/27/2012)	Fuel oil Generators (2)	none	< 52 non-emergency hrs/yr PM/PM10/PM2.5: 15 ppm sulfur SO2: 15 ppm CO: 84.0 tpy	1341 hp
		fire pump engine (3 engines)	Good Combustion Practices and limited hours of non-emergency operation	Good Combustion Practices and limited hours of non-emergency operation SO2: 15 ppm sulfur CO2: 84.0 tpy	575 hp each
Entergy Louisiana LLC	LA-0254 (8/16/2011)	emergency diesel generator	Proper operation and good combustion practices	CO2: 163.0 lb/MMBtu CH4: 0.0061 lb/MMBtu N2O: 0.0014 lb/MMBtu	1250
			ULSD and good combustion practices	CO: 2.6 g/hp-hr PM10/PM2.5: 0.15 g/hp-hr VOC: 1.0 g/hp-hr	
		emergency fire pump	Proper operation and good combustion practices	CO2: 163.0 lb/MMBtu CH4: 0.0061 lb/MMBtu N2O: 0.0014 lb/MMBtu	350
			ULSD and good combustion practices	CO: 2.6 g/hp-hr PM10/PM2.5: 0.15 g/hp-hr VOC: 1.0 g/hp-hr	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (hp)
Lake Charles Cogen, LLC	LA-0231 (6/22/2009)	emergency diesel generator	None	Comply with NSPS CO: 0.62 lb/hr NOx: 17.09 lb/hr PM10: 0.06 lb/hr SO2: 0.01 lb/hr	1341 (each)
		fire water diesel pumps (3)	None	Comply with NSPS CO: 0.37 lb/hr NOx: 6.02 lb/hr PM10: 0.08 lb/hr SO2: 0.01 lb/hr	575 (each)
Associated Electric Coop.	OK-0129 (1/23/2009)	emergency diesel generator	Low sulfur diesel 0.05% S and good combustion	Comply with NSPS CO: 12.66 lb/hr (3.5 g/Kw-hr) NOx: 23.15 lb/hr (6.4 g/KW-h) PM10: 0.72 lb/hr (0.2 g/kW-h) SO2: 0.89 lb/hr VOC: 1.55 lb/hr	2200
		emergency diesel fire pump	Low sulfur diesel and good combustion	Comply with NSPS CO: 2.6 g/hp-hr NOx: 4.59 lb/hr (7.8 g/hp-hr) PM10: 0.24 lb/hr (0.4 g/hp-h) SO2: 0.11 lb/hr VOC: 0.66 lb/hr	267
Cornell University	NY-0101 (3/12/2008)	emergency diesel generators	800 hr/yr limit (combined for both) Ultra-low sulfur diesel at 15 ppm	NSPS PM/PM10/PM2.5: 0.19 lb/hr, 20 % opacity H2SO4: 0.002 lb/hr	1000 kW
Western Farmers Electric Coop	OK-0118 (2/9/2007)	emergency diesel generator and fire pump	Good combustion practices and limited hours	Low sulfur fuel (< 0.5%)	not listed

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

(a)

Emission Unit	ID	Pollutant	Limitation	
Emergency Diesel Generator	EU-6006	PM	0.20 g/kW-hr	Use of Tier II diesel engine
		PM10	0.20 g/kW-hr	
		PM2.5	0.20 g/kW-hr	
		SO$_2$	15 ppm in fuel	
		NOx + NMHC	6.40 g/kW-hr	
		CO	3.50 g/kW-hr	
		Opacity	Acceleration: 20% Lugging: 15% Peak: 50%	
		CO$_2$e	811 tons per twelve (12) consecutive month period with compliance determined at the end of each month	
Emergency Diesel Firewater pump	EU-6009	PM	0.20 g/kW-hr	Engine that complies with Table 4, 40 CFR 60, Subpart IIII
		PM10	0.20 g/kW-hr	
		PM2.5	0.20 g/kW-hr	
		SO$_2$	15 ppm in fuel	
		NOx + NMHC	4.00 g/kW-hr	
		CO	3.50 g/kW-hr	
		CO$_2$e	217 tons per twelve (12) condecutive month period with compliance determined at the end of each month	

(c) Emergency generator (EU-6006) and emergency fire pump (EU-6009) shall use good combustion practices and shall use energy efficiency.

BACT Analysis
Hydrogen Plant

NOx

Step 1: Identify Potential Control Technologies

NOx emissions can be controlled with the following control technologies:

Post-combustion controls:
(1) Selective Catalytic Reduction (SCR)
(2) Selective Non-Catalytic Reduction (SNCR)

Combustion controls:
(3) Low NOx Burner (LNB)/Ultra low-Nox burner (ULNB)
(4) Flue Gas Recirculation (FGR)

Selective Catalytic Reduction (SCR)
Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to water and N_2. Under optimal conditions, SCR has a removal efficiency up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR can operate in a flue gas window ranging from 480°F to 800°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. In this particular service, the minimum target temperature is approximately 750ºF. Temperatures below the optimum decrease catalyst activity and allow NH3 to slip through; above the optimum range, ammonia will oxidize to form additional NOx. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH3:NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

Selective Non-Catalytic Reduction (SNCR)
With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2000°F, without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction.

At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of competing reactions for the direct oxidation of ammonia that forms NOx becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_x control performance requires that the furnace exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range and steady operation within that temperature window.

Low NOx Burners (LNB)
Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible.

Flue Gas Recirculation (FGR)
Recirculating a portion of the flue gas to the combustion zone can lower the peak flame temperature and result in reduced thermal NOx production. The flue gas recirculation (FGR) can be highly effective technique for lowering NOx emissions from burners and it's relatively inexpensive to apply. FGR lowers NOx emissions in two ways; the cooler, relatively inert, recirculated flue gases act as heat sink, absorbing heat from the flame and lowering peak flame temperatures and when mixed with the combustion air, recirculated flue gases lower the average oxygen content of the air, starving the NOx-forming reactions for one of the needed ingredients.

Step 2: Eliminate Technically Infeasible Options:

Technology	BACT Evaluation
Selective Catalytic Reduction (SCR) Technically Feasible – **Yes**	Selective Catalytic Reduction (SCR) is technically feasible.
Selective Non-Catalytic Reduction (SNCR) Technically Feasible – **No**	Riverview will operate at a wide range of load levels, with lower levels potentially unable to provide a temperature profile that maintains the range needed for effective control for sufficient residence time to achieve proper control. Some ammonia will be emitted. The combustion units used at Riverview combust a combination of gaseous fuels that are proportionally variable over relatively short time periods and results in short term NOx loading variations. This variability woks against the limited temperature flexibility and difficulty of SNCR in adjusting to short term changes maintaining consistent NOx control during operation of these units. For these reasons, the SNCR is technically infeasible.
Low NOx Burner (LNB) Technically Feasible - **Yes**	LNB/ULNB is technically feasible.
Flue Gas Recirculation (FGR) Technically Feasible – **Yes**	Flue Gas Recirculation (FGR) is technically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Control Option	Expected Control Efficiency
LNB/ULNB	40-85%
SCR	70%-90%
FGR	15-50%

Step 1: Identify Potential Control Technologies

For CO, PM/PM10/PM2.5, SO2, VOC and CO2e, the available control technologies are the same as listed under "BACT Analysis Natural gas-fired heaters and boiler" section above.

Step 2: Eliminate Technically Infeasible Options and
Step 3: Rank the Remaining Control Technologies by Control Effectiveness:

For CO, PM/PM10/PM2.5, SO2, VOC and CO2e, there are no add-on control devices that are considered feasible; therefore no ranking is necessary. See "BACT Analysis Natural gas-fired heaters and boiler" above for evaluations of each pollutant.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following tables summarize other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Hydrogen Plant - PM/PM$_{10}$/PM$_{2.5}$

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*Hydrogen Reformers (EU-7001 and EU-7002)*	*Combustion of natural gas, good combustion practices and energy efficiency*	*PM/PM10:* *0.0060 lb/MMBtu* *PM2.5:* *0.0048 lb/MMBtu*	*838.6 (each)*
NatGasoline LLC	TX-0656 PSDTX1340, 107764 (5/6/2014)	reformer	Good combustion practices and fuel selection	PM/PM10: 43.72 tpy (equivalent to 0.006 lb/MMBtu) PM2.5: 32.79 tpy (equivalent to 0.0048 lb/MMBtu)	1552
Flint Hills Resources Pine Bend LLC	MN-0093 03700011-101 (1/13/2017) (draft)	No. 4 hydrogen plant reformer-refining equipment (EQUI 471) (natural gas, refinery fuel gas)	clean fuel, GCP	PM10/PM2.5: 0.0075 lb/MMBtu	744.40
Ticona Polymers	TX-0774 PSDTX1438, GHGPSDTX (11/12/2015)	Reformer	Good combustion practices and firing of high hydrogen process gas, and firing of pipeline quality natural gas	PM10/PM2.5: 5.74 tpy (equivalent to 0.0048 lb/MMBtu)	1190
Although the process is the same, this source is in SIC code 2869 and may not establish BACT for the proposed source.					
Sasol Chemicals (USA) LLC	LA-0289 PSD-LA-778 (5/23/2014) (GTL unit)	Furnaces (EQT 964 & 965) (process gas)	gaseous fuel, GCP	PM10/PM2.5: 2.94 lb/hr 10.61 tpy 0.0075 lb/MMBtu	390.10
The GTL project was reportedly cancelled in November 2017, therefore this entry is not considered to represent BACT for the proposed source.					
Air Products and Chemicals, Inc.	LA-0264 PSD-LA-750 (M1) (9/4/2012)	reformer - Hydrogen Plant	Proper equipment designs, good combustion practices, and gaseous fuel	PM/PM10/PM2.5: 11.24 lb/hr 0.0075 lb/MMBtu	1320
Although the process is the same, this source is in SIC code 2813 and may not establish BACT for the proposed source.					
BP Products North America Inc	OH-0329 P0103694 (8/7/2009)	reformer heater	no add on controls were reasonably cost effective	PM10: 3.9 lb/hr 16.94 tpy 7.6 lb/MMBtu AP-42 factor *(sic)*	519.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hyd. reformer furnace flue gas vent	Proper design, operation, and good engineering practices	PM10: 0.0075 lb/MMBtu	1412.5
Air Products	TX-0526 NA 63, 39693 (8/18/2006)	reformer furnace stack - Hydrogen	SCR	PM10: 16.7 lb/hr 63.0 tpy (0.0075 lb/MMBtu)	1373
Although the process is the same, this source is in SIC code 4931 and may not establish BACT for the proposed source.					
Arizona Clean Fuels Yuma, LLC	AZ-0046 1001205 (4/14/2005)	Hyd. Reformer heater	None	PM10: 0.0075 lb/MMBtu	1435
Source may not have been constructed under this permit, therefore this citation is not considered representative of BACT.					

Hydrogen Plant - SO_2

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*Hydrogen Reformers (EU-7001 and EU-7002)*	*Use of low sulfur gas, good combustion practices and energy efficiency*	*0.005 gr S/scf in fuel gas*	*838.6 (each)*
The source has proposed a limit of 0.005 gr S/scf in fuel gas, this is determined to be BACT.					
Sasol Chemicals (USA) LLC	LA-0289 PSD-LA-778 (5/23/2014) (GTL unit)	Furnaces (EQT 964 & 965) (process gas)	use of gaseous fuel with a sulfur content of no more than 0.005 gr/scf (ann avg)	23.21 lb/hr max (ea) 2.09 tpy annual (ea)	390.1
The GTL project was reportedly cancelled in November 2017, therefore this entry is not considered to represent BACT for the proposed source.					
Diamond Shamrock Refining LP	TX-0580 92929 HAP63 (12/30/2010)	Hydrogen production unit furnace (refinery gas (PSA purge gas) w/ natural gas)		sulfur content of the fuel limited to 5 gr/100 dscf (ann avg)	355.65
BP Products North America Inc	OH-0329 P0103694 (8/7/2009)	reformer heater	none	15.52 lb/hr 38.00 tpy 20 ppmv dry at 0% excess air	519.00
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	hydrogen reformer furnace flue gas vent (48-08)	use of low sulfur fuel gas	25 ppmv (as H_2S)	1412.5
Air Products	TX-0526 NA 63, 39693 (8/18/2006)	reformer furnace stack - Hydrogen	SO_2 limit based on 45 ppmv total sulfur in fuel gas	7.3 lb/hr (28.0 tpy)	1373
Although the process is the same, this source is in SIC code 4931 and may not establish BACT for the proposed source.					
Arizona Clean Fuels Yuma, LLC	AZ-0046 1001205 (4/14/2005)	Hyd. Reformer heater	None	S (as H_2S) limited to 35 ppmv	1435
Source may not have been constructed under this permit, therefore this citation is not considered representative of BACT.					

Hydrogen Plant - NOx

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*Hydrogen Reformers (EU-7001 and EU-7002)*	*SCR with low NOx burners*	*0.0065 lb/MMBtu*	*838.6 (each)*

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Air Liquide Large Industries U.S. LP	TX-0738 87575, N116 (2/19/2010)	reformer	SCR	0.0065 lb/MMBtu (annual) 0.015 lb/MMBtu (24-hr) NH3 slip 10 ppmvd@15% O_2	1041
Although this source is in SIC code 2813, not 2911 like the proposed source, the NOx limitation of 0.0065 lb/MMBtu is the most stringent; therefore it has been determined to be BACT because of the similarity of the processes.					
Citgo Petroleum Corp	LA-0326 PSD-LA-222(M-2) (11/7/2017)	3(XXIII)2 C-reformer B-503, B-504, B-505 furnace (refinery fuel gas/reformer hydrogen)	GCP w/ continuous O2 monitor	83.13 lb/hr 0.095 lb/MMBtu (1-hr block avg)	875.00
		3(XXIII)1 C-reformer B-501, B-502, B-506 furnaces		47.12 lb/hr 0.19 lb/MMBtu (1-hr block avg)	248.00
Ticona Polymers	TX-0774 PSDTX1438, GHGPSDTX (11/12/2015)	Reformer	SCR	0.01 lb/MMBtu (12-mo avg.) 0.015 lb/MMBtu (24-mo avg.)	
Although the process is the same, this source is in SIC code 2869 and may not establish BACT for the proposed source.					
Sasol Chemicals (USA) LLC	LA-0289 PSD-LA-778 (5/23/2014) (GTL unit)	Furnaces (EQT 964 & 965) (process gas)	ULNB, SCR	19.73 lb/hr 14.24 tpy 0.01lb/MMBtu (30-day avg)	390.10
The GTL project was reportedly cancelled in November 2017, therefore this entry is not considered to represent BACT for the proposed source.					
NatGasoline LLC	TX-0657 PSDTX1340, 107764 (5/6/2014)	reformer	SCR	59.42 tpy (0.01 lb/MMBtu)	1552
Air Products and Chemicals, Inc.	LA-0264 PSD-LA-750 (M1) (9/4/2012)	reformer - Hydrogen Plant	ULNB and SCR	48.74 lb/hr 0.015 lb/MMBtu	1320
Although the process is the same, this source is in SIC code 2813 and may not establish BACT for the proposed source.					
Diamond Shamrock Refining LP	TX-0580 92929 HAP63 (12/30/2010)	Hydrogen production unit furnace (refinery gas (PSA purge gas) w/ natural gas)	LNB + SCR	0.0150 lb/MMBtu (hourly max) 0.0100 lb/MMBtu (ann avg) ammonia slip <10ppmv at 3% O2	355.65
Air Liquide Large Industries U.S. LP	TX-0591 N116 (2/19/2010)	Reformer - hydrogen production	low NOx-burner and SCR	0.0065 lb/MMBtu (annual) 0.015 lb/MMBtu (24-hr) at 3% O_2	876.6
Although the process is the same, this source is in SIC code 2813 and may not establish BACT for the proposed source.					
BP Products North America Inc	OH-0329 P0103694 (8/7/2009)	reformer heater	none	23.40 lb/hr 79.56 tpy 40 ppmvd @ 0% excess air (24 hr)	519
Air Products	TX-0526 NA 63, 39693 (8/18/2006)	reformer furnace stack - Hydrogen	SCR	81.0 lb/hr 87.0 tpy 90% CE	1373
Although the process is the same, this source is in SIC code 4931 and may not establish BACT for the proposed source.					
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	hydrogen reformer furnace flue gas vent (48-08)	SCR (voluntary) and ULNB	0.0125 lb/MMBtu	1412.5

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Arizona Clean Fuels Yuma, LLC	AZ-0046 1001205 (4/14/2005)	Hyd. Reformer heater	SCR and low Nox burners	0.0125 lb/MMBtu Ammonia: 5 ppmvd	1435
Source may not have been constructed under this permit, therefore this citation is not considered representative of BACT.					

Hydrogen Plant - VOC

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*Hydrogen Reformers (EU-7001 and EU-7002)*	*Combustion of natural gas, good combustion practices and energy efficiency*	*0.0015 lb/MMBtu*	*838.6 (each)*
NatGasoline LLC	TX-0657 PSDTX1340, 107764 (5/6/2014)	reformer	Good combustion practices	5 ppm 10.16 tpy (equivalent to 0.0015 lb/MMBtu)	1552
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hyd. reformer furnace flue gas vent	Proper design, operation, and good engineering practices	0.0015 lb/MMBtu	1412.5
Ticona Polymers	TX-0774 PSDTX1438, GHGPSDTX (11/12/2015)	Reformer	Good combustion practices and firing of high hydrogen process gas, and firing of pipeline quality natural gas	26.27 tpy	
Although the process is the same, this source is in SIC code 2869 and may not establish BACT for the proposed source.					
Sasol Chemicals (USA) LLC	LA-0289 PSD-LA-778 (5/23/2014) (GTL unit)	Furnaces (EQT 964 & 965) (process gas)	GCP, subpart 5D tuneups	2.13 lb/hr 7.68 tpy 0.0054 lb/MMBtu	390.10
Project was reportedly cancelled in November 2017, therefore this source is not considered representative of BACT for the proposed source.					
BP Products North America Inc	OH-0329 P0103694 (8/7/2009)	reformer heater	none	2.80 lb/hr 12.28 tpy 5.50 lb/MMCF AP-42 factor	519
Air Products	TX-0526 NA 63, 39693 (8/18/2006)	reformer furnace stack - Hydrogen	-	3.6 lb/hr (14.0 tpy)	1373
Although the process is the same, this source is in SIC code 4931 and may not establish BACT for the proposed source.					

Hydrogen Plant - CO

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*Hydrogen Reformers (EU-7001 and EU-7002)*	*Combustion of natural gas, good combustion practices and energy efficiency*	*CO: 0.02 lb/MMBtu*	*838.6 (each)*
The source has proposed a limit of 0.020 lb.MMBtu, equivalent to 25 ppmvd, which is more restictive than other sources. Therefore this has been determined to be BACT.					
Ticona Polymers	TX-0774 PSDTX1438, GHGPSDTX (11/12/2015)	Reformer	Flare (SSM)	CO: 50 ppmvd@ 3% O2	
Although the process is the same, this source is in SIC code 2869 and may not establish BACT for the proposed source.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Sasol Chemicals (USA) LLC	LA-0289 PSD-LA-778 (5/23/2014) (GTL unit)	Furnaces (EQT 964 & 965) (process gas)	GCP, subpart 5D tuneups	CO: 13.81 lb/hr 49.83 tpy 0.035 lb/MMBtu	390.10
Project was reportedly cancelled in November 2017, therefore this source is not considered representative of BACT for the proposed source.					
NatGasoline LLC	TX-0656 PSDTX1340, 107764 (5/6/2014)	reformer	Good combustion practices	CO: 50 ppm 177.4 tpy	1552
Diamond Shamrock Refining LP	TX-0580 92929 HAP63 (12/30/2010)	Hydrogen production unit furnace (refinery gas (PSA purge gas) w/ natural gas)		CO: 100 ppmv @ 3% O2 (max) 50 ppmv @3% O2 (ann avg)	355.65
BP Products North America Inc	OH-0329 P0103694 (8/7/2009)	reformer heater	cites 40 CFR 63, subpart DDDDD as case-by-case MACT	CO: 18.6 lb/hr (equivalent to 50 ppm)	519
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hyd. reformer furnace flue gas vent	Proper design, operation, and good engineering practices	CO: 0.04 lb/MMBtu	1412.5
Arizona Clean Fuels Yuma, LLC	AZ-0046 1001205 (4/14/2005)	Hyd. Reformer heater	None	CO: 0.01 lb/MMBtu	1435
Source may not have been constructed under this permit, therefore this citation is not considered representative of BACT.					

Hydrogen Plant - CO_2e

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*Hydrogen Plant 1 and Hydrogen Plant 2 (EU-7001 & EU-7002)*	*Combustion of natural gas, good combustion practices and energy efficiency*	*CO2e: 987,271 tons/yr (ea)*	*838.6 (each)*
Dakota Prairie Refining	ND-0031 PTC12090 (2/21/2013)	Hydrogen plant heater	Combustion of clean fuels and energy efficiency	CO2e: 12587 tpy	
		Hydrogen plant process CO2e emissions	none	CO2e: 21094 tpy	
CO2e: Combustion of clean fuels and energy efficiency is the most stringent; therefore it has been determined to be BACT.					
Flint Hills Resources Pine Bend LLC	MN-0093 03700011-101 (1/13/2017) (draft)	No. 4 hydrogen plant reformer-refining equipment (EQUI 471) (natural gas, refinery fuel gas)	clean fuel, GCP	CO2e: 771,156 tpy 365°F stack temp (365-day avg)	740.00
Ticona Polymers	TX-0774 PSDTX1438, GHGPSDTX (11/12/2015)	Reformer	Good combustion practices and firing of high hydrogen process gas, and firing of pipeline quality natural gas, heat integration and best management practices	CO2e: 533629 tpy	
Although the process is the same, this source is in SIC code 2869 and may not establish BACT for the proposed source.					
DE City Refining	DE-0025 APC-2015/0058-C (7/13/2015)	Steam-Methane Reformer with Pressure Swing Adsorption System	None	CO2e: 33.2 tons CO2/MMDscf H2	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Sasol Chemicals (USA) LLC	LA-0289 PSD-LA-778 (5/23/2014) (GTL unit)	Furnaces (EQT 964 & 965) (process gas)	natural gas feedstock, GCP	CO2e: 338,362 tpy	390.10
Project was reportedly cancelled in November 2017, therefore this source is not considered representative of BACT for the proposed source.					
Wynnewood Refinery Co LLC	OK-0160 2007-026-C(M-5) (1/7/2014)	H2 reformer (natural gas)	energy efficiency	CO2e: 120280 lb CO2e/MMscf NG feed	126.00
Phillips 66 Co.	LA-0263 PSD-LA-760 (7/25/2012)	Steam methane reformer (2291-SMR, EQT 0196) (refinery fuel gas)	GCP, PSA H2 purification	CO2e: 183,784 t/yr 0.05 lb/scf prdn (12-mo avg)	216.00

Hydrogen Plant Deaerators

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Hydrogen Plant Deaerators (EU-7003 & EU-7004)*	*None*	*VOC: 3.20 lb/hr* *CO: 1.06 lb/hr* *CO2e: 1,080 tons/yr (ea)*	*838.6 (each)*
VOC, CO, and CO_2e limits proposed by the source as BACT.					
Marathon Petroleum - Garyville Refinery	LA-0211 PSD-LA-719 (12/17/2006)	Hydrogen Plant Deaerator vent	None	VOC and CO: No limits	3125 lb/hr
Hunt Refining	AL-0242 X063 through X072 (5/20/2008)	Hydrogen plant degassifier	None (no controls are considered economically feasible)	None	-

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

(a) The units shall burn only gaseous fuels.

(b) PM, PM_{10}, and $PM_{2.5}$ emissions from each reformer shall not exceed:

Emission Limitations[1]	
Pollutant	**lb/MMBtu**
PM	0.006
PM_{10}*	0.006
$PM_{2.5}$*	0.0048

Notes:
1. PM shall include only filterable PM. PM_{10} and $PM_{2.5}$ shall include filterable and condensable.

(c) Sulfur content of the fuel gas delivered to each reformer shall not exceed 0.005 gr/scf.

(d) The units shall use selective catalytic reduction (SCR) with low-NOx burners for NOx control.

(e) NOx emissions from each reformer shall not exceed:

Emission Limitations	
Pollutant	**lb/MMBtu**
NOx	0.0065

(f) VOC emissions from each reformer shall not exceed:

Emission Limitations	
Pollutant	**lb/MMBtu**[1]
VOC	0.0015

Notes:
1. 1-hr average

(g) CO emissions from each reformer shall not exceed:

Emission Limitations	
Pollutant	**lb/MMBtu**
CO	0.020

(h) The CO_2e emissions from Block 7000 hydrogen production operations shall not exceed the values shown in the table below per twelve (12) consecutive month period, with compliance determined at the end of each month.

Emission Limitations	
Unit ID	**CO_2e Limit (tons)**
EU-7001	987,271
EU-7002	987,271
EU-7003	1,080
EU-7004	1,080

(h) VOC emissions from the hydrogen plant deaerators (EU-7003 and EU-7004) shall not exceed 3.20 b/hr, each.

(i) CO emissions from the hydrogen plant deaerators (EU-7003 and EU-7004) shall not exceed 1.06 lb/hr, each.

BACT Analysis
Wastewater Treatment

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following control technologies for control of VOC emissions from wastewater treatment processes:

(a) VOC destruction methods
(b) VOC removal methods
(c) Wastewater treatment process design

Step 2: Eliminate Technically Infeasible Options

(a) VOC destruction methods
VOC destruction processes, e.g., incineration, are not techinically feasible for wastewater streams containing minor amounts of organic compounds. The fuel value of the VOC content is insufficient to support vaporization of the water phase without very substantial use of supplemental fuel. Application of destruction technology to a wastewater stream also requires entirely different unit construction from typical air pollution control devices, i.e., a liquid injection incinerator rather than a flare.

(b) VOC removal
Certain removal processes, such as activated carbon adsorption, are applicable to removal of contaminants from water streams. However, these are generally applied as point-of-use systems for removing trace contaminants from clean streams like drinking water. Oily contaminants and unpredictable suspended solids loading cause plugging in activated carbon systems so adsorption processes are not feasible for wastewater treatment at the proposed source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM, OAQ has ranked the control technologies in order of effectiveness as follows:

(a) Conformance with the requirements of 40 CFR 60, Subpart QQQ; 40 CFR 61, Subpart FF; and 40 CFR 63, Subpart CC; including but not limited to covered oil-water separators, water seal drains, and closed vent systems. (estimated 96% control based on AP-42 Section 5.1)

The applicant proposed a wastewater collection and treatment system compliant with 40 CFR 60, Subpart QQQ which is top BACT. Therefore, a ranking is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Wastewater treatment*	-	*VOC emissions from the wastewater treatment vent (EU-8001), oily water sump (EU-8002), and MH1 (EU-8003) shall not exceed 20 ppmvd, each*	NA
Castleton Commodities International Corpus Christi	TX-0756 116072 & PSDTX1388 (6/19/2015)	Wastewater treatment plant	Overall system to achieve 90% of VOC from treated wastewater. Oil/water separator is enclosed and routed to a carbon adsorption system (CAS). Process drains to be equipped with a water seal. Wastewater sewers will be enclosed. Aerobic digesters will be enclosed and directed to a CAS.	4.56 lb/hr 9.04 tpy 90% overall control	-

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Magellan Processing LP	TX-0731 118270 & PSDTX1398 (4/10/2015)	Petroleum refining wastewater and wastewater treatment	Process wastewater shall be immediately directed to a covered system. All lift stations, manholes, junction boxes, conveyances, and any other wastewater facilities shall be covered and all emissions routed to a vapor combustor with a guaranteed DRE of 99% for control.	0.4 tpy	-
Specification of DRE is considered as specific for the emissions control device (i.e., vapor combustor), not as an achievable overall control efficiency for VOC emissions from wastewater collection and treatment processes.					
Valero Refining New Orleans LLC	LA-0213 PSD-LA-619 (M5) (11/17/2009)	Wastewater collection & treament: refinery	WW (EQT0255): comply with LA refinery MACT WWTU (EQT0359): comply with 40 CFR 61 subpart FF CRUIDS *(sic)* (EQT369): comply with 40 CFR 63 subparts F & G	-	-
Sunoco Inc	OH-0308 04-01447 (2/29/2009)	wastewater streams	-	91.19 tpy	-
This entry is identified as MACT, therefore it is not considered to establish BACT for the proposed source.					
Conoco Phillips	IL-0103 06050052 (8/5/2008)	wastewater treatment plant	Good air pollution control practices	-	-
This entry is identified as LAER, therefore it is not considered to establish BACT for the proposed source.					

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM, OAQ has established the following as VOC BACT for wastewater collection and treatment operations:

(a) VOC emissions from the wastewater treatment vent (EU-8001), oily water sump (EU-8002), and manhole no. 1 (EU-8003) shall not exceed 20 parts per million by volume (dry) (ppmvd), each.

BACT Analysis
VOC Leaks

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following control technologies for VOC control from fugitive emission sources:

(a) Leak Detection and Repair Program (LDAR)
(b) No Control Option

Step 2: Eliminate Technically Infeasible Options

(a) Leak Detection and Repair Program (LDAR)
A leak detection and control program (LDAR) is a systematic method of finding and eliminating fugitive emissions from leaking pumps, valves, compressors, pipe fitting, sampling connections, etc. LDAR is a work practice that assists sources identify leaking equipment so that emissions can be reduced though systematic repair or replacement. The key to the effectiveness of fugitive emission control is the regularly scheduled inspections and a defined

repair/replacement schedule. The use of an LDAR program is a technically feasible control option for the fugitive VOC emissions.

(b) No Control Option
It is possible that fugitive emissions from a source are so small that the time and cost required to establish and implement an LDAR program are not cost effective. Fugitive VOC emissions were estimated by the source at 14.39 tons per year. The use of no control is a technically feasible control option for the fugitive VOC emissions.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM, OAQ has ranked the control technologies in order of effectiveness as follows:

(a) LDAR (98% control)
(b) No Control (0% control)

The applicant proposed an LDAR program which is top BACT. Therefore, a ranking is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Fugitive VOC*	*LDAR Program per 40 CFR 60, Subpart GGGa*	*Block 2000: 151.18 tpy* *Block 4000: 25.04 tpy*	NA
Gravity Midstream Corpus Christi LLC	9342A, 9343A, PSDTX963M1 (10/31/2016)	equipment leaks	quarterly monitoring, 40 CFR 60, subparts GGG & GGGa	8.72 tpy	-
Phillips 66 Co	LA-0283 PSD-LA-696 (M-3) (8/14/2015)	unit fugitives for low sulfur gasoline unit (294-FF, FUG 0004)	LDR: Louisiana MACT determination for refinery equipment leaks (fugitive emission sources) dated 7/26/1994	15.43 lb/hr 67.59 tpy	-
Motiva Enterprises LLC	TX-0759 6056, PSDTX1062M2, GHG121 (7/31/2015)	hydrocracking and hydrotreating fugitive components	enhanced LDAR program, 500 ppmv leak definition	147.66 tpy	-
Midwest Fertilizer Corporation	IN-0173 T129-33576-00059 (6/4/2014)	fugitve emissions (F-1)	LDAR Program 40 CFR 60, Subpart VVa	None	NA
Sasol Chemicals (USA) LLC	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	GTL unit fugitive emissions (FUG 15)	LDAR program per 40 CFR 63, subpart FFFF	none	89.13 tpy
GTL project was reportedly cancelled in November 2017.					
Ohio Valley Resources	IN-0179 T147-32322-00062 (9/25/2013)	process fugitive VOC	LDAR Program 40 CFR 60, Subpart VVa	-	NA
The permit for this source was revoked.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Southeast Renewable Fuels	FL-0322 PSD-FL-412, 0510032-001-AC (12/23/2010)	Fugitives FUG0030	LDAR Program 40 CFR 60, Subpart VVa	6.52 tpy	NA
Valero, Hydrogen Plant	LA-0245 PSD-LA-750 (12/15/2010)	hydrogen plant fugitives (FUG0030)	LDAR pgm that meets LA refinery MACT with consent decree enhancements (7/26/1994)	23.74 tpy	NA
Sabina Petrochemicals	TX-0575 N018M1 (8/20/2010)	ALKFUG, BDEFUG, UTILFUG	state LAER LDAR program	9.01 tpy	NA
Requirements for this source are LAER and therefore not applicable in determining BACT for the proposed source.					
Highlands Ethanol Facility	FL-0318 PSD-FL-406, 0550061-001-AC (12/10/2009)	Fugitive VOC Emissions	LDAR Program 40 CFR 60, Subpart VVa	19.60 tpy	NA
Conoco Phillips	LA-0197 PSD-LA-696 (M1) (7/21/2009)	unit fugitives	LDAR pgm that meets LA refinery MACT with consent decree enhancements (7/26/1994)	57.89 tpy	NA
Ohio River Clean Fuels LLC	OH-0317 02-22896 (11/20/2008)	equipment leaks	use of leakless/sealless or low-emission pumps, valves, and compressors. LDAR program, 40 CFR 60, subpart GGa	1.70 tpy	-
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Arizona Clean Fuels Yuma, LLC	AZ-0046 1001205 (4/14/2005)	equipment leaks	LDAR program, 40 CFR 63, subpart H	-	-

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT) and 326 IAC 8-1-6 (New Facilities; General Reduction Requirements), IDEM, OAQ has established the following as VOC BACT for fugitive VOC emissions:

(a) Fugitive VOC emissions shall be controlled by a Leak Detection and Repair (LDAR) program. The leak detection and repair program specified in 40 CFR 60, Subpart GGGa shall serve as BACT for VOC fugitive emissions.

(1) Fugitive VOC emissions from Block 2000 VEBA Combi Cracker operations shall not exceed 151.18 tons per twelve (12) consecutive month period.

(2) Fugitive VOC emissions from Block 4000 offsites operations shall not exceed 25.04 tons per twelve (12) consecutive month period.

Particulate (PM, PM_{10} and $PM_{2.5}$) BACT Analysis
Roads

Step 1: Identify Potential Control Technologies

Emissions of particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}) and $PM_{2.5}$ from fugitive sources are generally controlled with measures to prevent the emissions from occurring. Generally, fugitive PM, PM_{10} and $PM_{2.5}$ emissions from roadways are controlled through one of the following mechanisms:

(1) Paving of Roadways
(2) Wet Suppression or Chemical suppression
(3) Good Housekeeping (cleanup spilled material)

Add-on particulate control devices such as cyclones, scrubbers, baghouses or ESP’s are not possible alternatives because the roadways cannot be enclosed and vented to a point source control device.

Step 2: Eliminate Technically Infeasible Options

Wet Suppression or Chemical suppression:
Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles. There are two types of wet suppression systems: liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems which supply foams as the wetting agent. Wet suppression systems typically achieve PM control efficiencies of greater than 85%.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Wet Suppression or Chemical suppression is a technically feasible option for the roads at this source.

Paving Roadways and Good Housekeeping
Paving all haul roads and prompt cleanup of any spilled or eroded materials are effective at minimizing dust emissions from vehicle traffic.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Paving haul roads reduces vehicle dust emissions versus unpaved surfaces and is feasible.

(2) Wet or chemical suppression (frequent use of water or chemical surfactants) can significantly reduce airborne dust emissions from both paved and unpaved roadways.

(3) Particulate emission from paved roadways can also be minimized with good housekeeping, i.e. cleaning up spills of solid material or dirt eroded onto the road surfaces.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following tables summarize other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Paved Roadways and Parking areas

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT
Riverview Energy	*Proposed*	*Paved Roads*	*All roads shall be paved*	*VE: 0% except for 1 min. in any 1-hr period* *Development, maintenance, and implementation of a fugitive dust control plan.*
V&M Star	OH-0344 (1/27/2011)	Paved Roads	watering, sweeping, chemical stabilization, or suppressants applied at sufficient frequencies	Paved & Unpaved roads PM: 38.3 tpy PM10: 7.7 tpy VE: 0% except for 1 min. every 60
Sun Coke Energy	OH-0332 (5/20/2010)	Paved Roads	Watering	PM: 1.08 tpy PM10: 0.21 tpy PM2.5: 0.05 tpy fugitive VE: No VE except for any 1 min in any 60 min.
New Steel International, Inc.	OH-0315 (5/6/2008)	Paved Roads	wet suppressants, watering, speed reduction and vacuuming or sweeping	PM: 153.4 tpy PM2.5: 29.9 tpy VE: 0% except for 1 min. every 60
Paving roads with watering, sweeping, chemical stabilization, or suppressants applied at sufficient frequencies is the most stringent. Therefore, this has been determined to be BACT. VE: 0% except for 1 min. every 60 is the most stringent. Therefore, this has been determined to be BACT.				
Midwest Fertilizer Corp.	IN-0173 T129-33576-00059 (6/4/2014)	Paved Roads	paving all haul roads, daily sweeping with wet suppression and prompt cleanup of any spilled materials	PM/PM10/PM2.5: 90 % control
90% control of fugitives is the most restrictive and is determined to be BACT.				
Ohio Valley Resources, LLC	IN-0179 T147-32322-00062 (9/25/2013)	Paved Roads	paving all plant haul roads, wet or chemical suppression and prompt cleanup of any spilled materials	PM/PM10/PM2.5: 90 % control
Note: This permit has been revoked and it is not clear whether the limits were tested, therefore this source is not considered in determining BACT for the proposed source.				
Indiana Gasification, LLC	IN-0166 T147-30464-00060 (6/27/2012)	Paved Roads	paving all plant haul roads, wet or chemical suppression and prompt cleanup of any spilled materials	PM/PM10/PM2.5: 90 % control
Note: This permit has been revoked and it is not clear whether the limits were tested, therefore this source is not considered in determining BACT for the proposed source.				
Rumpke Sanitary Landfill	OH-0330 (12/30/2008)	Paved Roads	water flushing, sweeping	PM: 58 tpy (paved & unpaved) PM10: 15.1 tpy (paved & unpaved) VE: 5% opacity as 3-min avg.
Ohio River Clean Fuels, LLC	OH-0317 (11/20/2008)	Paved Roads	Reduce speed limit, sweeping, watering and good housekeeping	PM: 79.0 tpy PM10: 15.39 tpy VE: No VE except for any 1 min in any 60 min.

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.				
Argos USA	SC-0132 (12/14/2007)	Paved Roads	Best mgmt practices consisting of sweeping and/or water flushing	PM
Entergy Louisiana, LLC	LA-0221 (11/30/2007)	Paved Roads	Newly constructed roads will be paved	PM10: 4.07 lb/hr (17.2 tpy)
Mesabi Nugget	MN-0061 13700318-001 (6/26/2005)	Paved Roads	Fugitive dust control plan	VE: 5% opacity
Martco Limited Partnership	LA-0203 (6/13/2005)	Paved Roads	Limited access	PM10: 2.6 lb/hr
Louisiana Generating, LLC	LA-0223 (1/8/2008)	Paved Roads	Pave all roads	PM10: 1.21 lb/hr 3.54 tpy

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

BACT shall be:

(a) The Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the paved roads shall be the development, maintenance, and implementation of a fugitive dust control plan, which shall include but not be limited to vacuum sweeping and water flushing as necessary and the implementation of a speed reduction plan.

(b) Visible emissions from truck traffic on plant roads shall not exceed one (1) minute in any one (1) hour period.

Air Quality Analysis

Riverview Energy Corporation
Dale, Indiana (Spencer, County)
Tracking and Plant ID: 147-39554-00065

Proposed Project

Riverview Energy Corporation (REC) plans to construct a Direct Coal Hydrogenation facility in Spencer County near Dale, Indiana. The facility will convert Indiana Number 5 high sulfur coal into low-sulfur liquid fuel products such as diesel, naphtha, and other saleable products. The site will be located south of Interstate 64 and east of U.S. 231. The Potential to Emit (PTE) is over 100 tons per year (TPY) for nitrous oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOCs), and over 25 TPY for particulate matter with an aerodynamic diameter of 10 micrometers and smaller (PM_{10}) and particulate matter with an aerodynamic diameter of 2.5 micrometers and smaller ($PM_{2.5}$). In addition, the facility will emit over 25 TPY of Hazardous Air Pollutants (HAPs). The HAP with largest emissions from the proposed facility is Methanol. Kellogg Brown and Root (KBR) were the consultants that submitted the modeling for REC.

Analysis Summary

Based on the potential emissions after controls, a Prevention of Significant Deterioration (PSD) air quality analysis was triggered for SO_2, PM_{10}, $PM_{2.5}$, CO, NO_x, VOCs, and HAPs. The significant impact analysis for 1-hour NO_2, all averaging times for SO_2, 24-hour and annual $PM_{2.5}$ showed that modeled concentrations exceeded the respective significant impact levels (SILs). A cumulative analysis was therefore required for those pollutants. No violation of the National Ambient Air Quality Standards (NAAQS) was found within the modeling domain for any of the required NAAQS analyses. Pre-construction monitoring is not required since modeled concentrations for the applicable pollutants were below the significant monitoring concentration thresholds. Existing monitoring is available for all pollutants and averaging times. An additional impact analysis was conducted and showed no further impact to vegetation, soils, visibility, endangered species, or economic growth. In addition a secondary ozone and $PM_{2.5}$ analysis was performed and no significant impacts were found from this proposed source. Finally, a Hazardous Air Pollutant (HAP) analysis was performed since emissions of one HAP (Methanol) were greater than 10 TPY. Based on the HAPs modeling results, the source will not pose a health concern.

Air Quality Impact Objectives

The purpose of the air quality impact analysis in the permit application is to accomplish the following objectives; each objective is individually addressed in this document in each section below.

A. Establish which pollutants require an air quality analysis based on Prevention of Significant Deterioration (PSD) significant emission rates.

B. Provide analyses of actual stack heights with respect to Good Engineering Practice (GEP), the meteorological data used, a description of the model used in the analysis, and the receptor grid used for the analyses.

C. Determine the significant impact level, the area impacted by the source’s emissions, and background air quality levels.

D. Demonstrate that the source will not cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) or PSD increment if the applicant exceeds significant impact levels.

E. Perform a qualitative analysis of the source's impact on general growth, soils, vegetation, and visibility in the impact area with emphasis on any Class I areas. The nearest Class I area is Kentucky's Mammoth Cave National Park.

F. Perform a secondary ozone and $PM_{2.5}$ analysis if the applicant is major for NO_2, VOCs, or SO_2.

G. Conduct a Hazardous Air Pollutant (HAP) analysis to determine cancer risk and hazard screening.

H. Summarize the Air Quality Analysis.

Section A – Pollutants Analyzed for Air Quality Impact

Applicability

The PSD requirements, 326 Indiana Administrative Code (IAC) 2-2, apply in attainment and unclassifiable areas and require an air quality impact analysis of each regulated pollutant emitted in significant amounts by a major stationary source or modification. Significant emission levels for each pollutant are defined in 326 IAC 2-2-1 and in the Code of Federal Regulations (CFR) 52.21(b)(23)(i). The proposed site in Spencer County is an attainment area for all applicable NAAQS.

Proposed Project Emissions

NO_x, PM_{10}, $PM_{2.5}$, CO, SO_2, VOCs, Lead (Pb) and HAPs are the pollutants that will be emitted from REC and are summarized in Table 1. NO_2, CO, PM_{10}, $PM_{2.5}$, SO_2, VOCs, and HAPs exceed the PSD significant emission rates; and air quality analysis is required for these pollutants.

TABLE 1
Significant Emission Rates for PSD

POLLUTANT	SOURCE EMISSION RATE (TPY)	SIGNIFICANT EMISSION RATE (TPY)	PRELIMINARY AQ ANALYSIS REQUIRED
NO_x	354.08	40	YES
CO	255.12	100	YES
$PM_{2.5}$	62.57	10	YES
PM_{10}	71.04	15	YES
SO_2	123.30	40	YES
VOCs	181.76	40	YES
Pb	0.00117	0.6	NO
HAPs	32.14	25[1]	YES
H_2S[2]	7.78	10	NO

[1] 10 tpy for a single HAP.
[2] There are no NAAQS for H_2S; however, there are monitoring concentrations thresholds for pollutants above the de minimis levels.

Section B – Good Engineering Practice (GEP), Meteorological Data, Model Used, Receptor Grid

Stack Height Compliance with Good Engineering Practice (GEP)

Applicability

Stacks should comply with GEP requirements established in 326 IAC 1-7-4. If stacks are lower than GEP, excessive ambient concentrations due to aerodynamic downwash may occur. Dispersion modeling credit for stacks taller than 65 meters or 213 feet is limited to GEP for the purpose of establishing emission limitations. The GEP stack height takes into account the distance and dimensions of nearby structures, which would affect the downwind wake of the stack. The downwind wake is considered to extend five times the lesser of the structure's height or width. A GEP stack height is determined for each nearby structure by the following formula:

$$H_g = H + 1.5L$$

Where : H_g is the GEP stack height
H is the structure's height
L is the structure's lesser dimension (height or width)

New Stacks

Since the new stack heights are below GEP stack height, the effect of aerodynamic downwash will be accounted for in the air quality analysis for the project.

Meteorological Data

The meteorological data used in the American Meteorological Society Environmental Protection Agency Regulatory Model (AERMOD) consisted of 2012 through 2016 surface meteorological data from the Evansville Regional Airport National Weather Service (NWS) Automated Surface Observing System (ASOS) station merged with the upper air data from the Lincoln, Illinois NWS. Additionally, the 1-minute ASOS wind speed and wind direction data were processed with the AERMINUTE preprocessor version 15272. The meteorological data were preprocessed into an AERMOD ready format by the Office of Air Quality (OAQ) using U.S. EPA's AERMET Version 16216, meteorological preprocessor for AERMOD. The meteorological data was processed with the adjusted u* values in accordance with Appendix W guidance as a regulatory option.

Model Description

OAQ used the most recent version of AERMOD (Version 18081 at the time the applicant submitted a modeling analysis) to determine maximum off-property concentrations or impacts for each criteria pollutant. AERMOD is U.S. EPA's preferred near field dispersion model and all regulatory default options were utilized in the U.S. EPA approved model, as listed in the 40 CFR Part 51, Appendix W "Revision to the Guideline on Air Quality Models." The Auer Land Use Classification Scheme was used to determine land use in the area. The area is considered primarily rural; therefore, a rural classification was used.

Receptor Grid

The receptor grid used by the consultants, KBR, was also used by OAQ. The grid was extended to a distance approximately 10 kilometers from the plant. Receptors were closely spaced at 50 meters along the plant fence line and out to a 0.5 km away from the plant fence line. A finely spaced grid with a 100 meter spacing extended out to a distance of 1.5 kilometers. A medium density Cartesian grid extended from 1.5 kilometers out to 3 kilometers with receptor spacing of 250 meters. Finally receptors were spaced 500 meters apart from 3 kilometers to 10 kilometers from the facility center.

Section C - Significant Impact Levels and Background

An analysis was conducted to determine the modeled impacts of the proposed facility. The highest 1st high concentrations for each pollutant and averaging time was determined and are shown below in Table 2. It was found that 1-hour NO_2, 1-hour, 3-hour, 24-hour and annual SO_2 were above their respective SILs. In addition, 24-hour and annual $PM_{2.5}$ were above their respective SILs. All other pollutants and averaging times for NAAQS and PSD analysis were below the SIL. A cumulative NAAQS analysis is required for pollutants and averaging times above their respective SILs. In determining the maximum modeled impacts presented in the SIL table below, care was taken to identify the worst case operating scenario of the facility. This involved modeling scenarios when flaring operations are planned. These flaring scenarios vary in duration from an hour to as long as a week. To ensure that the hourly standards were protected, the highest hourly rate was modeled for each hour over the 5 years of meteorological data in order to match the highest hourly emissions with the worst case meteorological conditions. Appendix A to this document lists results of the worst case scenarios determinations.

The flares were modeled as pseudo-point sources within AERMOD. Effective stack diameters were calculated according to a method used by the Texas Commission on Environmental Quality. In order to calculate the effective stack diameter, the gross heat release from the flare was calculated. The formula to calculate the effective diameter is shown below.

$$\mathrm{Ds} = \sqrt{q_n * 10^{-6}}$$

where q_n is the net heat release in calories per second and calculated as follows:

$$\mathrm{q_n} = q * (1 - 0.048 * \sqrt{MW})$$

where q is the gross heat release from the stack and MW is the mean molecular weight of the gas going to the flare.

The consultant for the source, KBR, has stated that when the flares are operating, the rest of the facility will be at a diminished operating capacity. IDEM has modeled the facility at or near full capacity for NO_2 and CO. The consultant presented a worst case flaring scenario for SO_2 during which the facility will be at partial capacity. The consultants' worst case SO_2 flaring scenario is reflected in Table 2.

TABLE 2
Significant Impact Levels

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS ($\mu g/m^3$)	SIGNIFICANT IMPACT LEVEL ($\mu g/m^3$)	ABOVE SIL ?
NO_2	1-hour	12.03	7.5	YES
NO_2	Annual	0.68	1	NO
CO	1-hour	32.53	2000	NO
CO	8-hour	14.40	500	NO
$PM_{2.5}$	Annual	0.32	0.3[2]	YES

$PM_{2.5}$	24-hour	1.72	1.2	YES
PM_{10}	Annual[1]	0.41	1	NO
PM_{10}	24-hour	2.18	5	NO
SO_2	1-hour	36.49	7.8	YES
SO_2	3-hour	32.10	25	YES
SO_2	24-hour	10.76	5	YES
SO_2	Annual	1.18	1	YES

[1] The annual PM_{10} NAAQS standard was revoked on October 17, 2006; however, the PSD standard remains in effect.

[2] The $PM_{2.5}$ SIL for the annual standard is 0.3 and unchanged in 40 CFR 51.165(b)(2). EPA has recently released guidance on SILS for ozone and fine particulates. A SIL of 0.2 is recommended for the annual standard in EPA's guidance.

Pre-construction Monitoring Analysis

Applicability

The PSD rule, 326 IAC 2-2-4, requires an air quality analysis of the new source or the major modification to determine if the pre-construction monitoring threshold is triggered. In most cases, monitoring data taken from a similar geographic location can satisfy this requirement if the pre-construction monitoring threshold has been exceeded. Also, post construction monitoring could be required if the air quality in that area could be adversely impacted by the applicant's emissions. REC did not exceed the de minimis levels for any of the pollutants or averaging times considered for preconstruction monitoring, as shown below in Table 3.

TABLE 3
Preconstruction Monitoring Analysis

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS (µg/m3)	DEMINIMIS LEVEL (µg/m3)	ABOVE DE MINIMIS LEVEL
NO_2	Annual	0.86	14	NO
PM_{10}	24-hour	4.18	10	NO
$PM_{2.5}$	24-hour	1.72	4[1]	N/A
SO_2	24-hour	5.30	13	NO

[1] On January 22, 2013, the DC Circuit Court of Appeals vacated the 24-hour $PM_{2.5}$ SMC (see Sierra Club v. EPA, 705 F.3d 458 (D.C. Cir. 2013). U.S. EPA promulgated rules on December 9, 2013 changing the $PM_{2.5}$ SMC at 40 CFR §§ 51.166(i)(5)(i) and 52.21(i)(5)(i) to 0 $\mu g/m^3$, meaning that there is no preconstruction monitoring exemption available (see 78 FR 73698.

Background Concentrations

Applicability

U.S. EPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (EPA-450/4-87-0007) Section 2.4.1 is cited for approval of the monitoring sites chosen for this area.

Background Monitors

Representative background concentrations used in the NAAQS analysis are listed in Table 4. The background monitors used for the NAAQS analysis were monitor ID number 18-141-0015, located in South Bend, IN for 1-hour NO_2, monitor ID number 18-163-0021, located in Evansville, IN, for 1-hour, 3-hour, 24-hour, and annual SO_2 and finally monitor number 18-147-0009 located in Dale, IN, for annual and 24-hour $PM_{2.5}$. The latest 3-year design value (2015-2017) for each of these monitors was used in the modeling analysis. These sites are considered the most representative sites with complete data relative to REC. For NO_2 background values, there are only two monitors within the state that have complete and quality assured data, both of which are in northern Indiana. The monitor in South Bend, Indiana is located in a more rural area than the Gary IITRI monitor, which is located in a more industrialized area. The more rural location of the NO_2 monitor in South Bend is comparable to the proposed location for REC.

TABLE 4
Background Concentrations

POLLUTANT	AVERAGING PERIOD	MONITOR ID	MONITOR LOCATION	MONITOR COUNTY	CONCENTRATION ($\mu g/m^3$)
NO_2	1-hour	18-141-0015	South Bend	St. Joseph	67.68
SO_2	1-hour	18-163-0021	Evansville	Vanderburgh	33.0
SO_2	3-hour	18-163-0021	Evansville	Vanderburgh	22.6
SO_2	24-hour	18-163-0021	Evansville	Vanderburgh	16.3
SO_2	Annual	18-163-0021	Evansville	Vanderburgh	3.6
$PM_{2.5}$	24-hour	18-147-0009	Dale	Spencer	19
$PM_{2.5}$	Annual	18-147-0009	Dale	Spencer	8.7

Section D - NAAQS and PSD Analysis

Based on the significant impact analysis, 1-hour NO_2, all SO_2 averaging times, as well as annual and 24-hour $PM_{2.5}$ were above their respective SILs and therefore required a refined NAAQS analysis. A PSD increment analysis was necessary for 3-hour, 24-hour, and annual SO_2 in addition to 24-hour and annual $PM_{2.5}$. U.S. EPA has not established PSD increments for 1-hour NO_2 and SO_2. Inventory sources included in the NAAQS modeling are listed in Table 5 below. Table 8-2 of Appendix W to 40 CFR Part 51, Guideline for Air Quality Models was utilized in determining appropriate modeled emissions for the inventory sources. Actual operating levels from Continuous Emission Monitoring Systems (CEMS) data was averaged over the most recent two-year period for sources for which this data was available. These sources with available operating level data from CEMS are as follows: ALCOA Power Plant, Indianapolis Power and Light – Petersburg, and Indiana Michigan Power – Rockport. Once the operating levels were established for each of the units located at the separate facilities, the emission limit for each of the units was multiplied by the operating factor in accordance with Table 8-2 of Appendix W to 40 CFR Part 51. Inventories from Kentucky were also compiled and included in the modeling for a conservative analysis.

TABLE 5
NAAQS Inventory

POLLUTANT	TIME AVERAGING PERIOD	INVENTORY SOURCE NAME	DISTANCE FROM PROPOSED SOURCE (km)
NO_2	1-hour	Indiana Michigan Power – Rockport	30
NO_2	1-hour	ALCOA Power Plant	44
NO_2	1-hour	ALCOA Operations	43
NO_2	1-hour	IPL – Petersburg	45
NO_2	1-hour	Owensboro Grain - KY	47
NO_2	1-hour	Owensboro Municipal - KY	45
NO_2	1-hour	Big Rivers Electric - KY	66
NO_2	1-hour	Domtar Paper - KY	42
NO_2	1-hour	Century Aluminum - KY	32
SO_2	1-hour / 3-hour 24-hour / Annual	Indiana Michigan Power – Rockport	30
SO_2	1-hour / 3-hour 24-hour / Annual	ALCOA Power Plant	44
SO_2	1-hour / 3-hour 24-hour / Annual	ALCOA Operations	43
SO_2	1-hour / 3-hour 24-hour / Annual	IPL-Petersburg	45
SO_2	1-hour / 3-hour 24-hour / Annual	Owensboro Grain – KY	47
SO_2	1-hour / 3-hour 24-hour / Annual	Owensboro Municipal – KY	45
SO_2	1-hour / 3-hour 24-hour / Annual	Big Rivers Electric – KY	66
SO_2	1-hour / 3-hour 24-hour / Annual	Domtar Paper – KY	42
SO_2	1-hour / 3-hour 24-hour / Annual	Century Aluminum - KY	32
$PM_{2.5}$	24-hour / annual	Indiana Michigan Power – Rockport	30
$PM_{2.5}$	24-hour / annual	ALCOA Power Plant	44
$PM_{2.5}$	24-hour / annual	ALCOA Operations	43
$PM_{2.5}$	24-hour / annual	IPL-Petersburg	45
$PM_{2.5}$	24-hour / annual	Owensboro Grain – KY	47
$PM_{2.5}$	24-hour / annual	Owensboro Municipal – KY	45
$PM_{2.5}$	24-hour / annual	Big Rivers Electric – KY	66
$PM_{2.5}$	24-hour / annual	Domtar Paper – KY	42

POLLUTANT	TIME AVERAGING PERIOD	INVENTORY SOURCE NAME	DISTANCE FROM PROPOSED SOURCE (km)
$PM_{2.5}$	24-hour / annual	Century Aluminum - KY	32
$PM_{2.5}$	24-hour / annual	Masterbrand Cabinets	10

Table 6 presents the results of the cumulative NAAQS modeling. All pollutants and averaging times were under their respective standards when representative background concentrations were included. For annual and 24-hour $PM_{2.5,}$ only the Significant Impact Area (SIA) receptors were included in the cumulative NAAQS modeling. The SIA receptors were those for which REC was found to exceed the SIL. For NO_2, a Tier I approach was used. This approach is the most conservative approach because it assumes that all modeled NO_X is converted to NO_2. No Tier II Ambient Ratio Method II (ARM II) approach was necessary. The PSD increment analysis is shown in Table 7. No pollutant consumed more than 80% of the available PSD increment.

TABLE 6
NAAQS Analysis

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED CONCENTRATION ($\mu g/m^3$)	BACKGROUND CONCENTRATION ($\mu g/m^3$)	COMBINED IMPACT ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	NAAQS VIOLATION
NO_2	1-hour	73.20	67.68	140.88	188.6	NO
SO_2	1-hour	110.01	33.0	143.01	196.2	NO
SO_2	3-hour	101.91	22.6	124.51	1300	NO
SO_2	24-hour	27.88	16.3	44.18	365	NO
SO_2	Annual	3.31	3.6	6.91	80	NO
$PM_{2.5}$	24-hour	4.77	19	23.77	35	NO
$PM_{2.5}$	Annual	0.86	8.7	9.56	12	NO

TABLE 7
PSD Increment Analysis

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED CONCENTRATION ($\mu g/m^3$)	PSD INCREMENT ($\mu g/m^3$)	PERCENT OF PSD INCREMENT (%)	INCREMENT VIOLATION
SO_2	3-hour	101.91	512	19.90	NO
SO_2	24-hour	27.88	91	30.63	NO
SO_2	Annual	3.31	20	16.55	NO
$PM_{2.5}$	24-hour	4.77	9	53.00	NO
$PM_{2.5}$	Annual	0.86	4	21.50	NO

Section E - Qualitative Additional Impacts Analysis

Additional Impact Analysis

All PSD permit applicants must prepare an additional impact analysis for each pollutant subject to regulation under the Act. This analysis assesses the impacts on growth, soils and vegetation, endangered species, and visibility caused by any increase in emissions of any regulated pollutant from the source. The REC modeling submittal provided an additional impact analysis prepared by KBR. IDEM reviewed their analysis and provides its review of the analysis below.

Economic Growth

The purpose of the growth analysis is to quantify project associated growth and estimate the air quality impacts from this growth either quantitatively or qualitatively. It is estimated that 200 jobs will be created as a result of this project and growth impacts related to the NAAQS and PSD increments are expected to be negligible. The proposed facility should not hinder other industrial growth in the area.

Soils and Vegetation Analysis

Soil types included clay and sandy clay over sandstone and shale. The land surrounding the site is primarily agricultural and the maximum modeled concentrations from REC are well below the threshold limits necessary to have adverse impacts on the surrounding vegetation. Crops in Spencer County and nearby areas consists mainly of corn, soybeans, wheat, and hay. Livestock in Spencer County consists of turkeys, hogs, and cattle and should not be adversely impacted from the facility. Trees in the area are mostly hardwoods and IDEM agrees with KBR’s analysis that no adverse impact is expected to the trees from this facility.

Federal and State Endangered Species Analysis

Federal and state endangered species are listed by the U.S. Fish and Wildlife Service; Division of Endangered Species for Indiana. This species list includes 4 birds, 10 fish, 3 mammals, 11 mussels, 2 reptiles, 3 insects and 6 plants. Of these species, 2 mussels, 1 bird, and 3 mammals are found within Spencer County. These species are found along rivers and lakes and in caves near water bodies and wooded areas. There are no federally endangered plant species found in Spencer County. Modeled impacts from REC are not expected to adversely impact these species.

Visibility Analysis

A visibility impairment analysis is conducted to demonstrate that emissions from the proposed project do no cause an impairment of visibility. A visibility impairment analysis must address near and long-range Class I area impacts and localized visibility. The Federal Land Managers’ Air Quality Related Values Work Group (FLAG) recommends procedures for proposed source locations near (within 50 km) and at large distances (greater than 50 km) from Class I areas. The nearest Class I area to the proposed source is Mammoth Cave National Park (120 km). For long range distances, FLAG recommends applying the Q/D initial screening test to determine whether or not further Class I area visibility analysis is necessary. Q is the total emissions of SO_2, NO_2, PM_{10}, and H_2SO_4 annual emissions from the proposed source and D is the total distance in kilometers from the Class I area. If Q/D is 10 or less, the proposed source is considered to have negligible visibility impacts on the Class I area. The results of the Q/D test for REC are shown in Table 8 below. Since Q/D is below 10 for the facility, no negligible visibility impairment is expected from the proposed source on the Class I area.

TABLE 8
Results of the Q/D Visibility Test on Mammoth Cave

Class I Area	NO_X Emissions (tpy)	SO_2 Emissions (tpy)	PM_{10} Emissions (tpy)	H_2SO_4 Emissions (tpy)	Total Emissions (Q, tpy)	Distance (D, km)	Q/D	Q/D ≤ 10
Mammoth Cave	354.08	123.30	71.04	16.99	565.4	120	4.8	YES

The VISCREEN model is designed as a screening model to determine the visual impact parameters from a single source plume on localized visibility. It is used to determine whether or not a plume is visible as an object itself. The visibility impairment analysis considers the impacts that occur within the impact area of the source as defined by the user distances. The user distances are determined by the nearest interstate or airport. For the current source, the nearest interstate would be I-64, 1 kilometer away from the proposed facility location. The background visual range used in this analysis was 25 km as suggested in Figure 9 in U.S. EPA's Workbook for Plume Visual Impact Screening and Analysis.

The NO_X and PM_{10} emission limits were used to run a local visibility Level 1 analysis. VISCREEN was used to determine if the color difference parameter (Delta-E) or the plume (green) contrast limits were exceeded. Delta-E was developed to specify the perceived magnitude of color and brightness changes and is used as the primary basis for determining the perceptibility of plume visual impacts. The plume constant can be defined at any wavelength as the relative difference in the intensity (called spectral radiance) between the viewed object and its background. This is used to determine how the human eye responds differently to different wavelengths of light. Worst case emissions were used for the Riverview facility. The results of the VISCREEN Level 1 analysis are presented in Table 9. The potential emission rates used in this analysis are 64.15 tons/year of particulates and 184.53 tons per year of Nitrous Oxides (NO_x). None of the critical criteria values for the color contrast and Green contrast were exceeded for the Riverview project.

TABLE 9
Results from the VISCREEN Level 1 Analysis

Distance	Background	Theta (degrees)	Azimuth (degrees)	Distance (km)	Alpha (degrees)	Color Contrast – DELTA E		Green Contrast	
						Criteria	Plume	Criteria	Plume
1 km	SKY	10	1	1	168	2	1.500	0.05	0.015
1 km	SKY	140	1	1	168	2	0.169	0.05	-0.009
1 km	TERRAIN	10	1	1	168	2	1.846	0.05	0.022
1 km	TERRAIN	140	1	1	168	2	0.488	0.05	0.020

Section F – Secondary Analysis for $PM_{2.5}$ and Ozone Formation

Air pollutants formed through chemical reactions in the atmosphere are referred to as secondary pollutants. Secondary $PM_{2.5}$ and ozone (O_3) are closely related in that they share common sources of emissions and are formed in the atmosphere from chemical reactions with similar precursors. Assessing the formation of secondary pollutants such as O_3 and $PM_{2.5}$ is useful for interpreting modeled impacts of precursor pollutants due to changes in emissions from new PSD major sources or PSD major modifications to that area.

In order to address this issue, the U.S. Environmental Protection Agency released updated version of the *Guideline on Air Quality Models* (published as Appendix W to 40 CFR Part 51). A significant modification to Appendix W addresses single-source impacts on ozone and secondary $PM_{2.5}$. Prior to releasing the final version of Appendix W, on December 2nd, 2016, U.S. EPA released the draft

Guidance on the Development of Modeled Emission Rates for Precursors (MERPS) As a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program (MERPS Guidance). This guidance provides states, local agencies, and tribes with modeled emission rates of hypothetical facilities that emit precursor pollutants to ozone and $PM_{2.5}$ that a source could use to determine its contribution to secondary pollution formation. If a future source or modification to a source emits less than a pollutant's MERP based on a representative hypothetical facility, then the new source or modification would not be considered as contributing to an exceedance of a critical air quality threshold for that pollutant, and further air quality analysis is not required. If the source or modification does not pass a Tier 1 demonstration, then a Tier 2 analysis utilizing refined assessment methods including photochemical grid models would be needed.

MERPS Assessment

Within the MERPS Guidance, there were three hypothetical facilities modeled in Indiana, located in Dubois, Grant, and Porter Counties. The lowest MERP value for each pollutant was selected for a conservative analysis. Table 10 lists the MERPS values used for this analysis. The significant impact level (SIL) for each pollutant's NAAQS was selected as the critical air quality threshold value for this MERP analysis. The SIL are as follows: 8-hour ozone – 1 part per billion (ppb); 24-hour $PM_{2.5}$ – 1.2 micrograms per cubic centimeter (µg/m^3); and annual $PM_{2.5}$ – 0.3 µg/m^3.

TABLE 10
Default MERP Values (tpy) for Riverview

Precursor	8-Hour Ozone	24-hour $PM_{2.5}$	Annual $PM_{2.5}$
NO_X	234	2308	12500
SO_2	----	305	4688
VOC	1163	----	----

Riverview Energy Corporation (REC) has submitted an air permit application with the Indiana Department of Environmental Management (IDEM) to construct a direct coal hydrogenation facility in Spencer County, Indiana. REC's proposed emissions were calculated to be 184.5 tons per year of oxides of nitrogen (NO_X), 181.8 tons per year of Volatile Organic Compounds (VOCs), and 120.6 tons per year of sulfur dioxide (SO_2).

All of REC's emissions are below the MERP values for Indiana that the U.S. EPA provides in the MERPS Guidance. Therefore, REC is not expected to cause or contribute to a violation of the 8-hour ozone, 24-hour $PM_{2.5}$, or Annual $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS) based solely on each precursor pollutant emission rate.

SIL Assessment

The MERPS Guidance offers additional details on the analysis when both precursor pollutants are emitted at rates below the MERPS but above the Significant Emission Rate (SER). When this occurs, the cumulative impact of the pollutants must be analyzed and compared to the SIL. The following equations are used for the SIL analysis:

$$\text{For 8-hour ozone: } \frac{EMIS_{NO_X}}{MERP_{NO_X}} + \frac{EMIS_{VOC}}{MERP_{VOC}}$$

$$\text{For } PM_{2.5}\text{: } \frac{EMIS_{NO_X}}{MERP_{NO_X}} + \frac{EMIS_{SO_2}}{MERP_{SO_2}}$$

If the sum of these ratios is less than or equal to 1, then the source's impact would be expected to be below the SIL.

REC's results are as follows:

For 8-hour ozone, this sum of ratios is 0.945.

For 24-hour $PM_{2.5}$, this sum of ratios is 0.475.

For Annual $PM_{2.5}$, this sum of ratios is 0.040.

REC's primary $PM_{2.5}$ emissions are above the SER threshold of 10 tons per year, so dispersion modeling was conducted for primary $PM_{2.5}$. Therefore, a MERP analysis for the cumulative impacts of REC's primary $PM_{2.5}$ and precursor emissions compared to the SIL is necessary. The following equation is used for this analysis:

$$\text{For } PM_{2.5}\text{: } \frac{HMC_{PM_{2.5}}}{SIL_{PM_{2.5}}} + \frac{EMIS_{NO_X}}{MERP_{NO_X}} + \frac{EMIS_{SO_2}}{MERP_{SO_2}}$$

where $HMC_{PM_{2.5}}$ is the highest modeled concentration of $PM_{2.5}$.

If the sum of these ratios is less than 1, then the source will not have an impact above the SIL. REC's maximum modeled $PM_{2.5}$ dispersion impacts are 1.72 $\frac{\mu g}{m^3}$ for the 24-hour NAAQS and 0.32 $\frac{\mu g}{m^3}$ for the annual NAAQS.

REC's results are as follows:

For 24-hour $PM_{2.5}$, this sum of ratios is 1.9.

For Annual $PM_{2.5}$, this sum of ratios is 1.1.

Based on the Tier 1 SIL analysis, REC's proposed emissions are not expected to have an impact above the SIL for the 8-hour Ozone NAAQS. However, a Tier 1 cumulative analysis of REC's impact on the 24-hour and Annual $PM_{2.5}$ NAAQS is required.

Cumulative Assessment

IDEM utilizes guidance from the Georgia Department of Natural Resources – Environmental Protection Division on completing the cumulative analysis for the 24-hour $PM_{2.5}$ NAAQS. This guidance uses the following equation:

$$Background_{PM_{2.5}} + DV_{PM_{2.5}} + \left[\left(\frac{EMIS_{SO_2}}{MERP_{SO_2}} + \frac{EMIS_{NO_X}}{MERP_{NO_X}}\right) \times SIL_{PM_{2.5}}\right]$$

where $DV_{PM_{2.5}}$ is the maximum modeled dispersion impact of either the project source or the project source and inventory sources, depending on the location of the background $PM_{2.5}$ monitor in relation to the project source. In this case, IDEM is using the Dale $PM_{2.5}$ monitor as the background monitor. This monitor is relatively close to the project source, and would already account for inventory sources. Therefore, for this project $DV_{PM_{2.5}}$ is the maximum 24-hour and annual modeled impact from Riverview, 1.72 $\frac{\mu g}{m^3}$ and 0.32 $\frac{\mu g}{m^3}$ respectively. The 24-hour background $PM_{2.5}$ value is 19 $\frac{\mu g}{m^3}$, while the annual background value is 8.7 $\frac{\mu g}{m^3}$. If the result of this equation is less than or equal to the NAAQS, then the project does not cause or contribute to a violation of the NAAQS. Using the values given, the result of this equation for the 24-hour NAAQS is 21.29 $\frac{\mu g}{m^3}$, which is less than the standard of 35 $\frac{\mu g}{m^3}$. For the Annual NAAQS, the result of the equation is 9.03 $\frac{\mu g}{m^3}$, less than the standard of 12 $\frac{\mu g}{m^3}$. Therefore Riverview's emissions are not expected to cause or contribute to a violation of the 24-hour or Annual $PM_{2.5}$ NAAQS.

Summary

In summary, based on this Tier 1 MERPS analysis, REC's NO_x, SO_2, and VOC emissions are not expected to exceed the SIL for the 8-hour Ozone NAAQS, or cause or contribute to a violation of the 24-hour $PM_{2.5}$ NAAQS and the annual $PM_{2.5}$ NAAQS.

Section G – Hazardous Air Pollutant (HAP) Analysis

The Office of Air Quality currently requests data concerning the emission of 189 HAPs listed in the 1990 Clean Air Act Amendments (CAAA) that are either carcinogenic or otherwise considered toxic and may be used by industries in the State of Indiana. These substances are listed as air toxic compounds on the State of Indiana, Department of Environmental Management, Office of Air Quality's construction permit application Form GSD-08.

REC's potential emissions of aggregate HAPs are estimated to be over 30 tons per year. Methanol is approximately 24 tons per year for a single HAP.

The Unit Risk Factor (URF) is the upper-bound excess lifetime cancer risk estimated to result from continuous inhalation exposure to a pollutant over a 70 year lifetime. Multiplying the estimated concentration by the URF will produce a cancer risk estimate. The cancer risk estimate is the conservative probability of developing cancer from exposure to a pollutant or mixture of pollutants over a 70 year lifetime, usually expressed as the number of additional cancer cases in a given number of people, e.g. one in a million. For screening purposes at REC, the cancer estimates for each pollutant are considered to be additive when deriving the cumulative maximum individual cancer risk.

Non-cancer health effects are determined using the Reference Concentration (RfC). The RfC is an estimate of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. Dividing the estimated pollutant concentration by the RfC will determine the pollutant's Hazard Quotient (HQ). All of the HAPs' Hazard Quotients were added together to determine REC's Hazard Index (HI).

This HAP screening analysis uses health protective assumptions that overestimate the actual risk associated with emissions from REC. Estimates 1) assume a 70 year exposure time, 2) assume that all carcinogens cause the same type of cancer, 3) assume that all non-carcinogens have additive health effects, 4) assume maximum permit allowable emissions from the facility, and 5) use conservatively derived dose-response information. The risk analysis cannot accurately predict whether there will be observed health problems around REC; rather it identifies possible avenues of risk. Table 11 lists the Hazardous Air Pollutants associated with Riverview Energy and the HAP analysis.

TABLE 11
Hazardous Air Pollutant Modeling Results

Compound	Annual Concentration ($\mu g / m^3$)	Cancer URF ($\mu g / m^3)^{-1}$	Source of URF	Cancer Risk	Non-Cancer Chronic RfC ($\mu g / m^3$)	Source of IDEM RfC	Hazard Quotient
Methanol	1.31				20000	IRIS	6.57E-05
Hexane	0.1503				700	IRIS	2.15E-04
Formaldehyde	0.0008	1.3E-05	IRIS	1.06E-08	9.80	ATSDR	8.34E-05
Toluene	0.1524				5000	IRIS	3.05E-05
Benzene	0.0737	7.8E-06	IRIS	5.75E-07	30	IRIS	2.46E-03
Nickel	2.29E-05	2.4E-04	IRIS	5.49E-09	0.2	ATSDR	1.14E-04
Ammonia	1.8620				100	IRIS	1.86E-02
Hydrogen Sulfide	0.0338				2	IRIS	1.69E-02
Xylenes	0.1910				100	IRIS	1.91E-03

Compound	Annual Concentration (μg / m^3)	Cancer URF (μg / m^3)$^{-1}$	Source of URF	Cancer Risk	Non-Cancer Chronic RfC (μg / m^3)	Source of IDEM RfC	Hazard Quotient
Phenol	0.0020				200	CAL	1.02E-05
o-Cresol (2-Methylphenol)	0.0041				175	Region 9	2.32E-05
m-, p-Cresols	0.0020				600	CAL	3.39E-06
TOTALS (HAZARD INDEX)				∑ = 0.59E-07			∑ = 0.0404
IDEM STANDARD				< 1.0E-06			< 1
COMPARISON				BELOW			BELOW

The Hazard Index for the project does not exceed 1. Pollutants with a Hazard Quotient (HQ) greater than 1 are considered to be at concentrations that could represent a health concern. Hazard Quotients above 1 do not represent areas where adverse health effects will be observed but indicate that the potential exists.

The additive cancer risk estimate from all HAPs is 4.6 additional cancer cases in ten million people. This means if an individual was exposed to these HAPs continuously for 70 years, the risk of getting cancer from this exposure would be 4.60 in ten million. The US EPA considers one in ten thousand (1.0E-04) excess cancer risk to be the upper range of acceptability with an ample margin of safety. The probability for the general public to be exposed to these HAPs for 24 hours a day, seven days a week, 52 weeks a year for 70 years is minimal.

Section H – Summary of Air Quality Analysis

Riverview Energy Corporation applied for a permit to construct a Direct Coal Hydrogenation facility in Spencer County, Indiana. The facility had emissions above the significant emission rates for NO_x, VOCs, $PM_{2.5}$, PM_{10}, CO, SO_2, and HAPs. The facility had modeled concentrations above the SIL for 1-hour NO_2, all averaging times for SO_2, and 24-hour and annual $PM_{2.5}$. Because these pollutants were above the SIL, a refined air quality impact analysis was required. Nearby large emitters were compiled and included in the NAAQS and PSD increment modeling. Several sources in Indiana and Kentucky were included in the NAAQS and PSD Increment modeling. After background concentrations were added to the NAAQS modeling results, the final resulting concentrations were under the NAAQS and PSD increments for all averaging times and pollutants.

An analysis of secondarily formed $PM_{2.5}$ and ozone was conducted. It was determined that no significant impact from the facility was found from secondarily formed ozone. Cumulative assessment of 24-hour and annual $PM_{2.5}$ showed Riverview would not cause or contribute to a violation of the 24-hour and annual $PM_{2.5}$ NAAQS. In addition, an additional impacts analysis on vegetation, soils, visibility, and wildlife in the area was examined and found to show no adverse impacts on the surrounding area are expected. The cumulative cancer risk estimate from all HAPs is well below the excess cancer risk to the upper range of acceptability with an ample margin of safety. No significant impacts are expected from the proposed facility.

Appendix A

Worst-Case Modeling Scenario Determinations

Pollutant	Scenario	Averaging Time	H1H	Year(s)
CO	Normal Operation	1-hour	27.61	2015
		8-hour	11.29	2015
CO	Flaring Emergency Fast Depressure Test[1]	1-hour	32.53	2014
		8-hour	14.40	2012
SO_2	Normal Operation	1-hour	23.57	2012-2016
		3-hour	21.95	2013
		24-hour	7.72	2016
		Annual	0.69	2012
SO_2	Flaring Product Stripper CCSU – Purging Facility Operating Scenario 1[2]	1-hour	36.49	2012-2016
		3-hour	32.10	2015
		24-hour	10.76	2014
		Annual[3]	1.18	2012
SO_2	Flaring LPH Commissioning Cold Start-Up Scenario 2[2]	1-hour	16.62	2012-2016
		3-hour	16.22	2015
		24-hour	5.66	2015
		Annual[3]	0.68	2014
NO_2	Normal Operation	1-hour	12.03	2012-2016
		Annual	0.68	2012
NO_2	Flaring Emergency Fast Depressure Test[1]	1-hour	11.96	2012-2016
		Annual	0.59	2013
$PM_{2.5}$	Normal Operation	24-hour	1.72	2012-2016
		Annual	0.32	2012-2016
PM_{10}	Normal Operation	24-hour	2.18	2012-2016
		Annual	0.41	2012

[1] The facility was assumed to be operating at normal (full) capacity. The facility will actually not be operating under normal (full) capacity during the flaring scenario. Emissions in the flaring scenario presented here, therefore, are likely overestimated.

[2] The consultant, KBR, presented IDEM with several worst case scenarios. The rest of the facility will only be operating at partial capacity during these scenarios. The results presented represent the facility at partial capacity.

[3] The annual average result for flaring event reflects running the scenario for all hours of a given year. This is an overestimate as the actual number of hours for these scenarios is much smaller.

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EST. 1986

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Eric J. Holcomb
Governor

Bruno L. Pigott
Commissioner

October 24, 2018

Mr. Gregory Merle
Riverview Energy Corporation
15 East Putnam Avenue, Suite #210
Greenwich, CT 06830

Re: Public Notice
Riverview Energy Corporation
Permit Level: PSD/New Source Construction
And Title V Operating Permit
Permit Number: 147-39554-00065

Dear Mr. Merle:

Enclosed is a copy of your draft PSD/New Source Construction and Title V Operating Permit, Technical Support Document, emission calculations, and the Public Notice which will be printed in your local newspaper.

The Office of Air Quality (OAQ) has prepared two versions of the Public Notice Document. The abbreviated version will be published in the newspaper, and the more detailed version will be made available on the IDEM's website and provided to interested parties. Both versions are included for your reference. The OAQ has requested that The Journal Democrat in Rockport, Indiana publish the abbreviated version of the public notice no later than October 24, 2018. You will not be responsible for collecting any comments, nor are you responsible for having the notice published in the newspaper.

OAQ has submitted the draft permit package to the Lincoln Heritage Public Library, 105 North Wallace Street in Dale, Indiana. As a reminder, you are obligated by 326 IAC 2-1.1-6(c) to place a copy of the complete permit application at this library no later than ten (10) days after submittal of the application or additional information to our department. We highly recommend that even if you have already placed these materials at the library, that you confirm with the library that these materials are available for review and request that the library keep the materials available for review during the entire permitting process.

Please review the enclosed documents carefully. This is your opportunity to comment on the draft permit and notify the OAQ of any corrections that are needed before the final decision. Questions or comments about the enclosed documents should be directed to Doug Logan, Indiana Department of Environmental Management, Office of Air Quality, 100 N. Senate Avenue, Indianapolis, Indiana, 46204 or call (800) 451-6027, and ask for extension (317) 234-5328 or dial (317) 23405328.

Sincerely,

Vivian Haun

Vivian Haun
Permits Branch
Office of Air Quality

Enclosures
PN Applicant Cover Letter 1/9/2017

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Governor

Bruno L. Pigott
Commissioner

ATTENTION: PUBLIC NOTICES, LEGAL ADVERTISING

October 18, 2018

The Journal Democrat
PO Box 6
Rockport, IN 47635

Enclosed, please find one Indiana Department of Environmental Management Notice of Public Comment and Notice of Public Hearing for Riverview Energy Corporation, Spencer County, Indiana.

Since our agency must comply with requirements which call for a Notice of Public Comment, we request that you print this notice one time, no later than October 24, 2018.

Please send the invoice, notarized form, clippings showing the date of publication to Bo Liu, at the Indiana Department of Environmental Management, Accounting, Room N1340, 100 North Senate Avenue, Indianapolis, Indiana, 46204.

To ensure proper payment, please reference account # 100174737.

We are required by the Auditor’s Office to request that you place the Federal ID Number on all claims. If you have any conflicts, questions, or problems with the publishing of this notice or if you do not receive complete public notice information for this notice, please call Vivian Haun at 800-451-6027 and ask for extension 317-233-6878 or dial 317-233-6878.

Sincerely,

Vivian Haun

Vivian Haun
Permit Branch
Office of Air Quality

Permit Level: New Source Construction and PSD/Title V Operating Permit
Permit Number: 147-39554-00065

Enclosure
PN Newspaper.dot 1/9/2017

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Eric J. Holcomb
Governor

Bruno L. Pigott
Commissioner

October 24, 2018

To: Lincoln Heritage Public Library

From: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

Subject: **Important Information to Display Regarding a Public Notice for an Air Permit**

Applicant Name: Riverview Energy Corporation
Permit Number: 147-39554-00065

Enclosed is a copy of important information to make available to the public. This proposed project is regarding a source that may have the potential to significantly impact air quality. Librarians are encouraged to educate the public to make them aware of the availability of this information. The following information is enclosed for public reference at your library:

- Notice of a 30-day Period for Public Comment
- Request to publish the Notice of 30-day Period for Public Comment
- Draft Permit and Technical Support Document

You will not be responsible for collecting any comments from the citizens. Please refer all questions and request for the copies of any pertinent information to the person named below.

Members of your community could be very concerned in how these projects might affect them and their families. **Please make this information readily available until you receive a copy of the final package.**

If you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185. Questions pertaining to the permit itself should be directed to the contact listed on the notice.

Enclosures
PN Library 1/9/2017

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Eric J. Holcomb
Governor

Bruno L. Pigott
Commissioner

Notice of Public Comment

October 24, 2018
Riverview Energy Corporation
147-39554-00065

Dear Concerned Citizen(s):

You have been identified as someone who could potentially be affected by this proposed air permit. The Indiana Department of Environmental Management, in our ongoing efforts to better communicate with concerned citizens, invites your comment on the draft permit.

Enclosed is a Notice of Public Comment, which has been placed in the Legal Advertising section of your local newspaper. The application and supporting documentation for this proposed permit have been placed at the library indicated in the Notice. These documents more fully describe the project, the applicable air pollution control requirements and how the applicant will comply with these requirements.

If you would like to comment on this draft permit, please contact the person named in the enclosed Public Notice. Thank you for your interest in the Indiana's Air Permitting Program.

Please Note: *If you feel you have received this Notice in error, or would like to be removed from the Air Permits mailing list, please contact Patricia Pear with the Air Permits Administration Section at 1-800-451-6027, ext. 3-6875 or via e-mail at PPEAR@IDEM.IN.GOV. If you have recently moved and this Notice has been forwarded to you, please notify us of your new address and if you wish to remain on the mailing list. Mail that is returned to IDEM by the Post Office with a forwarding address in a different county will be removed from our list unless otherwise requested.*

Enclosure
PN AAA Cover Letter 1/9/2017

IDEM

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AFFECTED STATE NOTIFICATION OF PUBLIC COMMENT PERIOD DRAFT INDIANA AIR PERMIT

October 24, 2018

A 30-day public comment period has been initiated for:

Permit Number: **147-39554-00065**
Applicant Name: **Riverview Energy Corporation**
Location: **Dale, Spencer County, Indiana**

The public notice, draft permit and technical support documents can be accessed via the **IDEM Air Permits Online** site at:
http://www.in.gov/ai/appfiles/idem-caats/

Questions or comments on this draft permit should be directed to the person identified in the public notice by telephone or in writing to:

Indiana Department of Environmental Management
Office of Air Quality, Permits Branch
100 North Senate Avenue
Indianapolis, IN 46204

Questions or comments regarding this email notification or access to this information from the EPA Internet site can be directed to Chris Hammack at chammack@idem.IN.gov or (317) 233-2414.

Affected States Notification 1/9/2017

Mail Code 61-53

IDEM Staff	VHAUN 10/24/2018 Riverview Energy Corporation 147-39554-00065 DRAFT			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

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1		Gregory Merle Riverview Energy Corporation 15 E Putnam Ave Greenwich CT 06830 (Source RM)									
2		Ms. Francis Lueken 223 W. 10th Street, P.O. Box 206 Ferdinand IN 47532 *(Affected Party)*									
3		Rockport City Council and Mayors Office P.O. Box 151 Rockport IN 47635 *(Local Official)*									
4		Dr. Jeff Seyler Univ. of So Ind., 8600 Univ. Blvd. Evansville IN 47712 *(Affected Party)*									
5		Lincoln Heritage Public Library Hammond and Wallace Sts, P.O. Box 564 Dale IN 47523-0564 *(Library)*									
6		Ms. Kathy Tretter Dubois-Spencer Counties Publishing Co, Inc P.O. Box 38 Ferdinand IN 47532-0038 *(Affected Party)*									
7		Dale Town Council 606 W Medcalf Dale IN 47523 *(Local Official)*									
8		Spencer County Commissioners 200 Main St., Courthouse Rockport IN 47635 *(Local Official)*									
9		Spencer County Health Department Main Street Courthouse, 1st Floor, Room 1 Rockport IN 47635-1492 *(Health Department)*									
10		Mr. Mark Wilson Evansville Courier & Press P.O. Box 268 Evansville IN 47702-0268 *(Affected Party)*									
11		Chuck Botsko 12540 N Base Rd Gentryville IN 47537 *(Affected Party)*									
12		David Boggs 216 Western Hills Dr Mt Vernon IN 47620 *(Affected Party)*									
13		John Blair 800 Adams Ave Evansville IN 47713 (Affected Party)									
14		Mr. Stephen A. Lang KBR 601 Jefferson Street Houston TX 77002 *(Consultant)*									
15		Mr. Ray Streigel Dale Town Hall 103 S. Wallace Street - P. O. Box 117 Dale IN 47523 *(Local Official)*									

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1		Al Logsdon Commissioner Spencer County Board of Commissioners P. O. Box 733 Santa Claus IN 47579 (Local Official)									
2		I-64 Reality, LLC 602 Orchard Lane Huntingburg IN 47642 *(Affected Party)*									
3		Aneopam, Inc.. 1339 N. Washington Street Dale IN 47325 *(Affected Party)*									
4		Servus, Inc.. 4201 Mannheim Road Suite A Jasper IN 47546-9618 *(Affected Party)*									
5		Rebecca/Grandersen & Charity James 20333 N. CR 500 E. Dale IN 47523 *(Affected Party)*									
6		Mr. Vernon Geiss 7233 Old Vincennes Road Floyd Knobs IN 47119 *(Affected Party)*									
7		Gerald & Geraldine Brenner 4487 E. CR 2000 North Dale IN 47523 *(Affected Party)*									
8		Tempel Land & Livestock, LLC Tempel Land & Livestock, LLC 3805 E. CR 2000 N. Dale IN 47523 *(Affected Party)*									
9		Mr. Nicholas Gerlach 4405 E. CR 2000 North Dale IN 47523 *(Affected Party)*									
10		Mr. Roger Wilson 4443 East CR 2000 N. Dale IN 47253 *(Affected Party)*									
11		Mr. Virlee Waninger 4381 E. CR 2000 North Dale IN 57523 *(Affected Party)*									
12		Mr. Leander Tempel 4327 E. CR 2000 N. Dale IN 47523 *(Affected Party)*									
13		Dennis & Roger Forler P. O. Box 465 Santa Claus IN 47579 (Affected Party)									
14		Mr. Roger L. Payne 4130 East CR 2100 North Dale IN 47523 *(Affected Party)*									
15		Gene & Lola Michel P. O. Box 318 Santa Claus IN 47579 *(Affected Party)*									

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1		Myron Pugh 779 S. Thompson Drive Paoli IN 47454 (Affected Party)									
2		Ms. Gay Ann Harney Mayor of Rockport City Rockport City Hall 426 Main Street Rockport IN 47635 *(Local Official)*									
3		Mr. Tom Brown Spencer County Board of Commissioners 6378 E. CR 700 N. Grandview IN 47615 *(Local Official)*									
4		Mr. Larry Gries 20520 N. Gries Road Dale IN 47523 *(Affected Party)*									
5		Mr. Sylvester Gries 20670 North CR 515 East Dale IN 47523 *(Affected Party)*									
6		Robert & Ruth Gaesser 20861 N. CR 500 East Dale IN 47523 *(Affected Party)*									
7		Alyssa & Sean Sermersheim 20569 N. CR 500 East Dale IN 47523 *(Affected Party)*									
8		Charles & Janice Gogel 3209 Leslie Drive Jasper IN 47546 *(Affected Party)*									
9		Mr. Jack Kroeger Spencer County Council P. O. Box 668 Santa Claus IN 47579 *(Local Official)*									
10		Ms. Cindy Morrison Dale Town Hall P. O. Box 117 Dale 47 *(Local Official)*									
11		Mr. Jefferson Lindsey Spencer County Attorney 217 Main Street Rockport IN 47635 *(Local Official)*									
12		Hoosier Energy Rural Electric Cooperative P. O. Box 908 Bloomington IN 47402-0908 *(Affected Party)*									
13		Winkler, Inc.. P. O. Box 68 Dale IN 47523 (Affected Party)									
14		Howard E. Dunn 1201 NW Tullison Road, Apt. 249 Kansas City MO 64116 *(Affected Party)*									
15		Mr. Randy Vaal 422 W Prancer Dr N Santa Claus IN 47579 *(Affected Party)*									

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1		Gary Oeding 1625 Vienna Drive Ferdinand IN 47532 (Affected Party)									
2		Mr. Don Shepherd National Park Services 12795 W. Alameda Parkway Lakewood CO 80228 *(Affected Party)*									
3		Mark Oeding 412 E 12th St Ferdinand IN 47532 *(Affected Party)*									
4		Mr. James Seiler 2351 N. Orchard Road Rockport IN 47635 *(Local Official)*									
5											
6											
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Total number of pieces Listed by Sender 4	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

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