ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2022–0787; FRL–9846–02–OAR]

RIN 2060–AV80

National Emission Standards for Hazardous Air Pollutants: Ethylene Production, Miscellaneous Organic Chemical Manufacturing, Organic Liquids Distribution (Non-Gasoline), and Petroleum Refineries Reconsideration

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final action; reconsideration of final rule.

SUMMARY: On July 6, 2020, the U.S. Environmental Protection Agency (EPA or the Agency) finalized the residual risk and technology review (RTR) conducted for the Ethylene Production source category, which is part of the Generic Maximum Achievable Control Technology Standards National Emission Standards for Hazardous Air Pollutants (NESHAP); on July 7, 2020, the EPA finalized the RTR conducted for the Organic Liquids Distribution (Non-Gasoline) NESHAP; and on August 12, 2020, the EPA finalized the RTR conducted for the Miscellaneous Organic Chemical Manufacturing NESHAP. Amendments to the Petroleum Refinery Sector NESHAP were most recently finalized on February 4, 2020. Subsequently, the EPA received and granted various petitions for reconsideration on these NESHAP for, among other things, the provisions related to the work practice standards for pressure relief devices (PRDs), emergency flaring, and degassing of floating roof storage vessels. This action finalizes proposed amendments to remove the *force majeure* exemption for PRDs and emergency flaring, incorporate clarifications for the degassing requirements for floating roof storage vessels, and address other corrections and clarifications.

DATES: This final action is effective on April 4, 2024. The incorporation by reference of certain material listed in this rule was approved by the Director of the Federal Register as of August 12, 2020.

ADDRESSES: The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2022–0787. All documents in the docket are listed in *https://www.regulations.gov/.* Although listed, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. With the exception of such material, publicly available docket materials are available either electronically in *https://www.regulations.gov/* or in hard copy at the EPA Docket Center, WJC West Building, Room Number 3334, 1301 Constitution Avenue NW, Washington, DC. The Public Reading Room hours of operation are from 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact U.S. EPA, Attn: Mr. Michael Cantoni, Sector Policies and Programs Division, Mail Drop: E143–01, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, North Carolina 27711; telephone number: (919) 541–5593; and email address: *cantoni.michael@epa.gov.*

SUPPLEMENTARY INFORMATION: *Preamble acronyms and abbreviations.* We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

atm-m3/mol	atmospheres per mole per cubic meter
ACC	American Chemistry Council
AFPM	American Fuel and Petrochemical Manufacturers
AMEL	alternative means of emissions limitation
API	American Petroleum Institute
CAA	Clean Air Act
CBI	Confidential Business Information
CDX	Central Data Exchange
CEDRI	Compliance and Emissions Data Reporting Interface
CEMS	continuous emission monitoring systems
CFR	Code of Federal Regulations
CRA	Congressional Review Act
EMACT	Ethylene Production MACT
EPA	Environmental Protection Agency
GMACT	Generic Maximum Achievable Control Technology
HAP	hazardous air pollutant(s)
ICR	Information Collection Request
LEL	lower explosive limit
MACT	maximum achievable control technology
MCPU	miscellaneous organic chemical manufacturing process unit
MON	Miscellaneous Organic Chemical Manufacturing NESHAP
NAICS	North American Industry Classification System
NESHAP	national emission standards for hazardous air pollutants
NHV	net heating value
NOCS	notification of compliance status
NTTAA	National Technology Transfer and Advancement Act
OLD	Organic Liquids Distribution (Non-Gasoline)
OMB	Office of Management and Budget
ppm	parts per million
ppmv	parts per million by volume
psi	pounds per square inch
PRA	Paperwork Reduction Act
PRD	pressure relief device
RFA	Regulatory Flexibility Act
RTR	risk and technology review
TCEQ	Texas Commission on Environmental Quality
UMRA	Unfunded Mandates Reform Act

Organization of this document. The information in this preamble is organized as follows:

Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All
K. Congressional Review Act (CRA)

I. General Information

A. What is the source of authority for the reconsideration action?

The statutory authority for this action is provided by sections 112 and 307(d)(7)(B) of the Clean Air Act (CAA) (42 U.S.C. 7412 and 7607(d)(7)(B)).

B. Does this action apply to me?

Table 1 of this preamble lists the NESHAP and associated regulated industrial source categories that are the subject of this action. Table 1 is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that this action is likely to affect. The final standards will be directly applicable to the affected sources. Federal, State, local, and Tribal government entities are not affected by this action. Each of the source categories covered by this action were defined in the *Initial List of Categories of Sources Under Section 112(c)(1) of the Clean Air Act Amendments of 1990* (see 57 FR 31576; July 16, 1992) and *Documentation for Developing the Initial Source Category List, Final Report* (see EPA–450/3–91–030, July 1992), as well as the *National Emission Standards for Hazardous Air Pollutants; Revision of Initial List of Categories of Sources and Schedule for Standards Under Sections 112(c) and (e) of the Clean Air Act Amendments of 1990* (61 FR 28197; June 4, 1996), as presented here.

TABLE 1—NESHAP AND INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS FINAL ACTION

Source category	NESHAP	NAICS[1] code
Ethylene Production	40 CFR part 63, subparts XX and YY	325110.
Organic Liquids Distribution (Non-Gasoline)	40 CFR part 63, subpart EEEE	3222, 3241, 3251, 3252, 3259, 3261, 3361, 3362, 3399, 4247, 4861. 4869, 4931, 5622.
Miscellaneous Organic Chemical Manufacturing.	40 CFR part 63, subpart FFFF	3251, 3252, 3253, 3254, 3255, 3256, and 3259, with several exceptions.
Petroleum Refineries	40 CFR part 63, subpart CC	324110.

[1] North American Industry Classification System (NAICS).

The Ethylene Production source category includes any chemical manufacturing process unit in which ethylene and/or propylene are produced by separation from petroleum refining process streams or by subjecting hydrocarbons to high temperatures in the presence of steam. The ethylene production unit includes the separation of ethylene and/or propylene from associated streams such as a C_4 product,[1] pyrolysis gasoline, and pyrolysis fuel oil. The ethylene production unit does not include the manufacture of Synthetic Organic Chemical Manufacturing Industry (SOCMI) chemicals such as the production of butadiene from the C_4 stream and aromatics from pyrolysis gasoline.

The Organic Liquids Distribution (Non-Gasoline) source category includes, but is not limited to, those activities associated with the storage and distribution of organic liquids other than gasoline, at sites which serve as distribution points from which organic liquids may be obtained for further use and processing. The distribution activities include the storage of organic liquids in storage tanks not subject to other 40 CFR part 63 standards and transfers into or out of the tanks from or to cargo tanks, containers, and pipelines.

Following the initial source category listings, the Agency combined 21 of the 174 originally defined source categories, and other organic chemical processes which were not included in the original 174 source category list, into one source category called the ''Miscellaneous Organic Chemical Processes'' source category.[2] The Agency later divided the ''Miscellaneous Organic Chemical Processes'' source category into two new source categories called the ''Miscellaneous Organic Chemical Manufacturing'' source category and the ''Miscellaneous Coating Manufacturing'' source category.[3] The Miscellaneous Organic Chemical Manufacturing source category includes any facility engaged in the production of benzyltrimethylammonium chloride, carbonyl sulfide chelating agents, chlorinated paraffins, ethylidene norbornene, explosives, hydrazine, photographic chemicals, phthalate plasticizers, rubber chemicals, symmetrical tetrachloropyridine, oxybisphenoxarsine/1,3-diisocyanate, alkyd resins, polyester resins, polyvinyl alcohol, polyvinyl acetate emulsions, polyvinyl butyral, polymerized vinylidene chloride, polymethyl methacrylate, maleic anhydride copolymers, or any other organic chemical processes not covered by another maximum available control technology (MACT) standard. Many of these organic chemical processes involve similar process equipment, similar emission points and control equipment, and are in many cases co-located with other source categories.

The Petroleum Refineries sector includes two source categories. The Petroleum Refineries MACT 1 source category includes any facility engaged in producing gasoline, naphthas, kerosene, jet fuels, distillate fuel oils, residual fuel oils, lubricants, or other products from crude oil or unfinished petroleum derivatives. The refinery process units in this source category include, but are not limited to, thermal cracking, vacuum distillation, crude distillation, hydroheating/hydrorefining, isomerization, polymerization, lube oil processing, and hydrogen production. The Petroleum Refineries MACT 2—Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Recovery Units source category includes any facility engaged in producing gasoline, naphthas, kerosene, jet fuels, distillate fuel oils, residual fuel oils, lubricants, or other products from crude oil or unfinished petroleum derivates.

---

[1] The C_4 product stream is a hydrocarbon product stream from an ethylene production unit consisting of compounds with four carbon atoms (*i.e.,* butanes, butenes, butadienes).

[2] 61 FR 57602 (Nov. 7, 1996).

[3] 64 FR 63035 (Nov. 18, 1999).

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this final action will also be available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this final action at *https://www.epa.gov/stationary-sources-air-pollution/petroleum-refinery-sector-rule-risk-and-technology-review-and-new, https://www.epa.gov/stationary-sources-air-pollution/acetal-resins-acrylic-modacrylic-fibers-carbon-black-hydrogen, https://www.epa.gov/stationary-sources-air-pollution/miscellaneous-organic-chemical-manufacturing-national-emission,* and *https://www.epa.gov/stationary-sources-air-pollution/organic-liquids-distribution-national-emission-standards-hazardous.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version and key technical documents at these same websites.

Copies of all comments received on the proposed rulemaking (National Emission Standards for Hazardous Air Pollutants: Ethylene Production, Miscellaneous Organic Chemical Manufacturing, Organic Liquids Distribution (Non-Gasoline), and Petroleum Refineries Reconsideration) [4] are available at the EPA Docket Center Public Reading Room. Comments are also available electronically through *https://www.regulations.gov/* by searching Docket ID No. EPA–HQ–OAR–2022–0787.

Redline strikeout versions of each rule showing the edits that incorporate the changes finalized in this action are presented in the documents titled: *Final Regulatory Text Edits for Subpart EEEE, Final Regulatory Text Edits for Subpart FFFF, Final Regulatory Text Edits for Subpart YY,* and *Final Regulatory Text Edits for Subpart CC,* available in the docket for this action (Docket ID No. EPA–HQ–OAR–2022–0787).

II. Background

Following the EPA's finalization of the risk and technology reviews for the Ethylene Production (or EMACT), Organic Liquids Distribution (Non-Gasoline) (OLD), and Miscellaneous Organic Chemical Manufacturing (MON) NESHAP in 2020, the EPA also received petitions for reconsideration of these actions. The EPA also received a petition for reconsideration of the Petroleum Refinery Sector NESHAP raising some of the same issues.

To address selected issues for which we granted reconsideration and to provide other technical corrections, the EPA is finalizing revisions to the EMACT standards, OLD NESHAP, MON, and Petroleum Refineries NESHAP. The EPA is finalizing revisions to the work practice standards for PRDs and emergency flaring related to *force majeure* provisions in the EMACT standards, MON, and Petroleum Refineries NESHAP, and is finalizing standards for the degassing of storage vessels in the EMACT standards, OLD NESHAP, and MON. The EPA is also adding requirements for pressure-assisted flares and mass spectrometers to the Petroleum Refineries NESHAP to align this rule with other more recent chemical sector rules and eliminate the need to request site-specific alternative means of emission limitations (AMELs) for these units. In addition, the EPA is finalizing other technical corrections, clarifications, and correction of typographical errors in all rules. As explained in the proposed rule, the EPA requested comment only on specific issues identified in the document and explained that it would not address other issues or provisions of these final rules not specifically address in the proposed rule.

A. Ethylene Production

The MACT standards for the Ethylene Production source category (herein called the EMACT standards) are contained in the Generic Maximum Achievable Control Technology (GMACT) NESHAP, which also includes MACT standards for several other source categories. The EMACT standards were promulgated on July 12, 2002,[5] and codified at 40 CFR part 63, subparts XX and YY. As promulgated in 2002, and further amended,[6] the EMACT standards regulate hazardous air pollutant (HAP) emissions from ethylene production units located at major sources. An ethylene production unit is a chemical manufacturing process unit in which ethylene and/or propylene are produced by separation from petroleum refining process streams or by subjecting hydrocarbons to high temperatures in the presence of steam. The EMACT standards define the affected source as all storage vessels, ethylene process vents, transfer racks, equipment, waste streams, heat exchange systems, and ethylene cracking furnaces and associated decoking operations that are associated with each ethylene production unit located at a major source as defined in CAA section 112(a)(1).

Following promulgation of the EMACT standards in July 2020, the EPA received two petitions for reconsideration in September 2020. The EPA received a joint petition from the American Chemistry Council (ACC) and the American Fuel & Petrochemical Manufacturers (AFPM). The EPA also received a petition from Earthjustice (on behalf of RISE St. James, Louisiana Bucket Brigade, Louisiana Environmental Action Network, Texas Environmental Justice Advocacy Services, Air Alliance Houston, Community In-Power & Development Association, Clean Air Council, Center for Biological Diversity, Environmental Integrity Project, and Sierra Club). Copies of the petitions are provided in the docket for this action (see Docket Item No. EPA–HQ–OAR–2022–0787–0005 and EPA–HQ–OAR–2022–0787–0006). ACC/AFPM's petition requested that the EPA reconsider certain aspects of the final action including, among other things, the storage vessel degassing provisions, ethylene cracking furnace burner repair provisions, and ethylene cracking furnace isolation valve inspections. Earthjustice's petition requested that the EPA reconsider certain aspects of the final rule including, among other things, the *force majeure* and exemption allowances in the work practice standards for PRDs and emergency flaring. ACC/AFPM and Earthjustice also raised other issues that are not addressed in this rulemaking.

On April 19, 2022, the EPA informed the petitioners, ACC/AFPM, and Earthjustice that it would grant reconsideration of the provisions addressing the work practice standards for PRDs, emergency flaring, and degassing of floating roof storage vessels, under CAA section 307(d)(7)(B). The EPA also informed the petitioners of the continuing review of all issues raised in their petitions. A copy of the letter to the petitioners is available in the docket for this action (see Docket Item No. EPA–HQ–OAR–2022–0787–0022).

The EPA proposed the reconsideration of the EMACT standards to address these issues along with other technical corrections and clarifications and requested public comment.[7]

With the exception of out-of-scope comments, this final preamble provides summaries and responses to all comments received regarding the proposed reconsideration of the EMACT standards. Comments on the proposed

---

[4] 88 FR 25574 (Apr. 27, 2023).

[5] 67 FR 46258 (Jul. 12, 2002).

[6] 70 FR 19266 (Apr. 13, 2005); 85 FR 40386 (Jul. 6, 2020).

[7] 88 FR 25574 (Apr. 27, 2023).

reconsideration of the EMACT standards that we consider out of scope for this reconsideration rulemaking include comments on the standards for PRDs and emergency flaring that discuss topics other than the *force majeure* provisions.

B. Organic Liquids Distribution (Non-Gasoline)

The Organic Liquids Distribution (Non-Gasoline) (herein called OLD) NESHAP is codified at 40 CFR part 63, subpart EEEE.[8] Organic liquids are any crude oils downstream of the first point of custody transfer and any non-crude oil liquid that contains at least 5 percent by weight of any combination of the 98 HAP listed in table 1 of 40 CFR part 63, subpart EEEE. For the purposes of the OLD NESHAP, as promulgated in 2004, and further amended,[9] organic liquids do not include gasoline, kerosene (No. 1 distillate oil), diesel (No. 2 distillate oil), asphalt, and heavier distillate oil and fuel oil, fuel that is consumed or dispensed on the plant site, hazardous waste, wastewater, ballast water, or any non-crude liquid with an annual average true vapor pressure less than 0.7 kilopascals (0.1 pounds per square inch (psi)). Emission sources controlled by the OLD NESHAP are storage tanks, transfer operations, transport vehicles while being loaded, and equipment leak components (valves, pumps, and sampling connections) that have the potential to leak at major sources.

The EPA received three petitions for reconsideration for the OLD NESHAP in September 2020. The EPA received petitions from Stoel Rives LLP (on behalf of Alyeska Pipeline Company), the American Petroleum Institute (API) and AFPM, and Earthjustice (on behalf of California Communities Against Toxics, Coalition for a Safe Environment, and Sierra Club). Copies of the petitions are provided in the docket for this rulemaking (see Docket Item No. EPA–HQ–OAR–2022–0787–0015, EPA–HQ–OAR–2022–0787–0023, and EPA–HQ–OAR–2022–0787–0004). API/AFPM and Stoel Rives LLP (on behalf of Alyeska Pipeline Company) requested that the EPA reconsider its final action and specifically raised the issue of storage vessel degassing. In their respective petitions, API/AFPM, Stoel Rives, and Earthjustice also raised other issues that are not being addressed in this rulemaking.

On September 8, 2021, the EPA informed petitioners Stoel Rives, API/AFPM, and Earthjustice that it would grant reconsideration on certain issues, including the work practice standards for storage vessel degassing that apply broadly, under CAA section 307(d)(7)(B). Other issues for which EPA granted voluntary reconsideration in the September 8, 2021, letter (*e.g.,* work practice standards for venting from conservation vents on the Valdez Marine Terminal's crude oil fixed roof tanks and fenceline monitoring) are still being reviewed and are not part of this action. The EPA also stated in the letter to the petitioners that it is continuing to review all issues raised in the petitions. A copy of the letter to petitioners is available in the docket for this action (see Docket Item No. EPA–HQ–OAR–2022–0787–0016).

On April 27, 2023, the EPA proposed to reconsider, and requested comment on, the OLD NESHAP to address storage vessel degassing along with other technical corrections and clarifications.[10]

With the exception of out-of-scope comments, this final preamble provides summaries and responses to all comments received regarding the proposed reconsideration of the OLD NESHAP. Comments on the proposed reconsideration of the OLD NESHAP that we consider out of scope for this reconsideration rulemaking include comments on the standards for PRDs and emergency flaring that discuss topics other than the *force majeure* provisions and comments on requirements for temporary control devices.

C. Miscellaneous Organic Chemical Manufacturing

The NESHAP for the Miscellaneous Organic Chemical Manufacturing source category (herein called MON) is codified at 40 CFR part 63, subpart FFFF.[11] As promulgated in 2003, and further amended,[12] the MON regulates HAP emissions from miscellaneous organic chemical manufacturing process units (MCPUs) located at major sources. A miscellaneous organic chemical manufacturing process unit (MCPU) includes a miscellaneous organic chemical manufacturing process, as defined in 40 CFR 63.2550(i), and must meet the following criteria: it manufactures any material or family of materials described in 40 CFR 63.2435(b)(1); it processes, uses, or generates any of the organic HAP described in 40 CFR 63.2435(b)(2); and, except for certain process vents that are part of a chemical manufacturing process unit, as identified in 40 CFR 63.100(j)(4), the MCPU is not an affected source or part of an affected source under another subpart of 40 CFR part 63. An MCPU also includes any assigned storage tanks and transfer racks; equipment in open systems that is used to convey or store water having the same concentration and flow characteristics as wastewater; and components such as pumps, compressors, agitators, PRDs, sampling connection systems, open-ended valves or lines, valves, connectors, and instrumentation systems that are used to manufacture any material or family of materials described in 40 CFR 63.2435(b)(1). Sources of HAP emissions regulated by the MON include the following: process vents, storage tanks, transfer racks, equipment leaks, wastewater streams, and heat exchange systems.

Following promulgation of the MON in August 2020, the EPA received five petitions for reconsideration between October and December 2020. The EPA received petitions from the ACC (who submitted two petitions), the Texas Commission on Environmental Quality (TCEQ), Huntsman Petrochemical, LLC, and Earthjustice (on behalf of RISE St. James, Louisiana Bucket Brigade, Louisiana Environmental Action Network, Texas Environmental Justice Advocacy Services, Air Alliance Houston, Ohio Valley Environmental Coalition, Blue Ridge Environmental Defense League, Environmental Justice Health Alliance for Chemical Policy Reform, Sierra Club, Environmental Integrity Project, and Union of Concerned Scientists). Copies of the petitions are provided in the docket for this rulemaking (see Docket Item Nos. EPA–HQ–OAR–2022–0787–0007, EPA–HQ–OAR–2022–0787–0009, EPA–HQ–OAR–2022–0787–0010, EPA–HQ–OAR–2022–0787–0027, and EPA–HQ–OAR–2022–0787–0008). ACC's petitions requested that the EPA reconsider certain aspects of the final rule including, among other things, the storage vessel degassing provisions and requirements for ethylene oxide sources. Earthjustice's petition requested that the EPA reconsider certain aspects of the final rule including, among other things, the *force majeure* and exemption allowances for PRDs and emergency flaring. TCEQ, ACC, and Huntsman Petrochemical's petitions requested that the EPA reassess the MON risk assessment for issues around ethylene oxide risks. The EPA addressed ACC, TCEQ, and Huntsman Petrochemical's

---

[8] 69 FR 5038 (Feb. 3, 2004).

[9] 71 FR 42898 (Jul. 28, 2006); 73 FR 21825 (Apr. 23, 2008); 73 FR 40977 (Jul. 17, 2008), and 85 FR 40740 (Jul. 7, 2020).

[10] 88 FR 25574 (Apr. 27, 2023).

[11] 68 FR 63852 (Nov. 10, 2003).

[12] 70 FR 38562 (July 1, 2005); 71 FR 40316 (Jul. 14, 2006); and 85 FR 49084 (Aug. 12, 2020).

reconsideration petitions in a separate rulemaking.[13] Earthjustice and ACC also raised other issues that are not being addressed in this rulemaking.

On June 17, 2021, the EPA sent a letter to petitioners informing them that it is continuing to review all issues raised in the petitions. A copy of the letter to petitioners is available in the docket for this action (see Docket Item No. EPA–HQ–OAR–2022–0787–0017).

On April 27, 2023, the EPA proposed the reconsideration of the MON to address these issues along with other technical corrections and clarifications and requested public comment.[14]

With the exception of out-of-scope comments, this final preamble provides summaries and responses to all comments received regarding the proposed reconsideration of the MON. Comments on the proposed reconsideration of the MON that we consider out of scope for this reconsideration rulemaking include:

- Comments on the standards for PRDs and emergency flaring that discuss topics other than the *force majeure* provisions, including releases from PRDs in ethylene oxide service and PRD monitoring.
- Comments on surge control vessel or bottoms receiver vents.
- Comments on maintenance vent provisions.
- Comments on conservation vent provisions.

D. Petroleum Refineries

The EPA finalized amendments to the petroleum refinery sector rules as the result of an RTR.[15] These amendments included, among other provisions, adding work practice requirements to Petroleum Refinery MACT 1 (40 CFR part 63, subpart CC) for PRDs and flares in 40 CFR 63.648(j) and 63.670(o), respectively. These provisions specifically provide requirements for owners and operators to follow in the event of an atmospheric PRD release or emergency flaring event including performing root cause analysis for each event and implementing corrective action(s) in accordance with the rule requirements.

The EPA received three petitions to reconsider the December 2015 final rule. Two petitions were filed on January 19, 2016, and February 1, 2016, jointly by API and the AFPM. In response to API/AFPM's January 19, 2016, petition for reconsideration, the EPA issued a proposal on February 9, 2016,[16] and a final rule on July 13, 2016.[17] The third petition was filed on February 1, 2016, by Earthjustice on behalf of Air Alliance Houston, California Communities Against Toxics, the Clean Air Council, the Coalition for a Safe Environment, the Community In-Power & Development Association, the Del Amo Action Committee, the Environmental Integrity Project, the Louisiana Bucket Brigade, the Sierra Club, the Texas Environmental Justice Advocacy Services, and Utah Physicians for a Healthy Environment. In their petition, Earthjustice claimed that several aspects of the revisions to the Petroleum Refinery MACT 1 were not proposed; therefore, the public was precluded from commenting on the altered provisions during the public comment period, including, among other provisions, the work practice standard for PRDs and emergency flaring.

On June 16, 2016, the EPA informed petitioners it would grant reconsideration on issues where petitioners claimed they had not been provided an opportunity to comment. Subsequently, the EPA proposed the reconsideration of the Petroleum Refinery MACT 1 to address issues for which reconsideration was granted in the June 16, 2016, letters.[18] The EPA solicited public comment on five issues in the proposal related to the work practice standard for PRDs, the work practice standard for emergency flaring events, and the assessment of risk as modified based on implementation of these PRD and emergency flaring work practice standards. On February 4, 2020, the EPA issued a final action[19] setting forth its decisions on each of the five issues.

On April 6, 2020, Earthjustice submitted a petition for reconsideration of the February 2020 final action on behalf of Air Alliance Houston, California Communities Against Toxics, Clean Air Council, Coalition For A Safe Environment, Community In-Power & Development Association, Del Amo Action Committee, Environmental Integrity Project, Louisiana Bucket Brigade, Sierra Club, Texas Environmental Justice Advocacy Services, and Utah Physicians for a Healthy Environment (see Docket Item No. EPA–HQ–OAR–2022–0787–0029). The petition for reconsideration requested that the EPA reconsider five issues in the February 4, 2020, final rule: (1) The EPA's rationale that the PRD standards and emergency flaring standards are continuous; (2) the EPA's rationale for the PRD standards under CAA sections 112(d)(2) and (3); (3) the EPA's rationale for separate work practice standards for flares operating above the smokeless capacity; (4) the EPA's rationale for risk acceptability and risk determination; and (5) the EPA's analysis and rationale in its assessment of acute risk. The EPA initially denied the April 6, 2020, petition for reconsideration[20] and provided detailed responses to each of the five issues raised in the April 2020 petition in a September 3, 2020, letter, which is available in the Petroleum Refinery rulemaking docket (see Docket Item No. EPA–HQ–OAR–2010–0682–0999). After further consideration, on April 19, 2022, EPA informed petitioners that it would undertake reconsideration on select provisions related to the work practice standard for PRDs and emergency flaring (see Docket Item No. EPA–HQ–OAR–2022–0787–0003). Specifically, the EPA is reconsidering the inclusion of the *force majeure* allowances in the PRD and emergency flaring work practice standard. As noted in our April 19, 2022, letter, we may reconsider additional issues in the future.

On April 27, 2023, the EPA proposed the reconsideration of Petroleum Refinery MACT 1 to address the PRD and emergency flaring work practice standard along with other technical corrections and clarifications and requested public comment.[21]

With the exception of out-of-scope comments, this final preamble provides summaries and responses to all comments received regarding the proposed reconsideration of the Petroleum Refinery MACT 1. Comments on the proposed reconsideration of the Petroleum Refinery MACT 1 that we consider out of scope for this reconsideration rulemaking include comments on the standards for PRDs and emergency flaring that discuss topics other than the *force majeure* provisions.

III. Final Action

In this section of the preamble, the EPA sets forth its final decisions on the issues for which reconsideration was granted and on which the EPA solicited comment in the April 27, 2023, proposed rule.[22] We also present the Agency's rationale for the decisions. The EPA is finalizing revisions to the work practice standards for PRDs and emergency flaring related to *force majeure* provisions in the EMACT

---

[13] 87 FR 77985 (Dec. 21, 2022).

[14] 88 FR 25574 (Apr. 27, 2023).

[15] 80 FR 75178 (Dec. 1, 2015).

[16] 81 FR 6814 (Feb. 9, 2016).

[17] 81 FR 45232 (Jul. 13, 2016).

[18] 81 FR 71661 (Oct. 18, 2016).

[19] 85 FR 6064 (Feb. 4, 2020).

[20] 85 FR 67665 (April 6, 2020).

[21] 88 FR 25574 (Apr. 27, 2023).

[22] 88 FR 25574 (Apr. 27, 2023).

standards, MON, and Petroleum Refinery MACT 1 and is also finalizing clarifications for the degassing of storage vessels in the EMACT standards, OLD NESHAP, and MON. In addition, the EPA is finalizing requirements for pressure-assisted flares and mass spectrometers in the Petroleum Refinery MACT 1 to align this rule with other more recent chemical sector rules and to eliminate the need to request site specific alternative means of emission limitations (AMELs) for these units. Also, the EPA is finalizing other technical corrections, clarifications, and correction of typographical errors in all rules. The sections below provide a brief summary of each topic as well as summaries and responses to the comments received on each topic.

A. Pressure Relief Devices and Emergency Flaring

Topic summary: Petroleum Refinery MACT 1, EMACT standards, and the MON include work practice standards for PRDs and emergency flaring. These provisions specifically provide requirements for owners and operators to follow in the event of an atmospheric PRD release or emergency flaring event including performing root cause analysis for each event and implementing corrective action(s) in accordance with the rule requirements. The atmospheric PRD release and emergency flaring provisions specify the conditions which result in a violation of the work practice standards. The owner or operator is required to track the number of events by emission unit and root cause. An atmospheric PRD release or emergency flaring event for which the root cause is determined to be poor maintenance or operator error is a violation of the WPS. Two atmospheric PRD releases or two emergency flaring events from the same emission unit which are determined to be the result of the same root cause in a 3-year period is a violation of the work practice standard. Finally, three atmospheric PRD releases or three emergency flaring events from the same emission unit regardless of the root cause is a violation of the work practice standard (also referred to as ''the 'three strikes' provisions''). Notably, if the root cause is determined to be due to a *force majeure* event, as defined in 40 CFR 63.641, 40 CFR 63.1103(e)(2), and 40 CFR 63.2550, it does not count towards the criteria for a violation of the WPS. However, in reconsidering these provisions, the EPA has recognized that despite the term *force majeure* being carefully defined, the *force majeure* allowance in the work practice standards may present difficulties for determining compliance. It may also represent a provision that some facility owners or operators may seek to use to avoid incurring violations and pursuing potentially disruptive corrective actions. During the root cause analysis and corrective action process, owners or operators maintain discretion when categorizing and reporting the root cause of atmospheric PRD releases and emergency flaring events, thereby placing the onus on the EPA to determine whether the definition of *force majeure* was appropriately applied.

In light of these concerns, we reviewed periodic reports from refineries in Texas and Louisiana obtained through the EPA Regional Office (Docket ID No. EPA–HQ–OAR–2022–0787–0021 and EPA–HQ–OAR–2022–0787–0025). Based on the data available, we concluded that the frequency of these types of releases is lower than originally expected. We also found that by removing the *force majeure* allowance, the rule is strengthened, and compliance becomes easier to assess as it is determined purely based on the count of events by emission unit and root cause. As such, the EPA proposed to remove the *force majeure* provisions from the PRD and emergency flaring work practice standards. See section III.A. of the preamble to the proposed rule for additional details.[23]

Comments: A commenter supported the proposed decision to remove *force majeure* provisions from the PRD and emergency flaring work practice standards. The commenter stated that the EPA's evaluation of refinery periodic reports appropriately concluded the provisions are not needed and that compliance with the provisions would become easier for facilities and for the EPA to evaluate. The commenter further stated the *force majeure* provisions should be removed because they are unlawful and mean that an emission standard does not apply at all times for PRDs and flaring. The commenter contended that to ensure that standards apply at all times for PRDs, the EPA must specify that any uncontrolled release from a PRD is a violation of the standard. For a standard to apply at all times for flaring, the commenter asserted that the EPA has not shown how a flare will comply with the net heating value of the combustion zone limit and achieve 98 percent destruction while smoking.

Other commenters opposed the proposed decision to remove *force majeure* provisions from the PRD and emergency flaring work practice standards. Some of these commenters argued that the EPA evaluated too narrow of a dataset to identify *force majeure* events. They stated that evaluating data over a longer period is necessary, due to the infrequent nature of *force majeure* events. They also emphasized that the review was not representative of all affected source categories, because only data from petroleum refineries were analyzed. Furthermore, one commenter contended that considering the frequency of events was not an adequate basis for removing the provisions.

Some commenters stated it was not appropriate to remove the *force majeure* provisions because these events are beyond the control of a facility and a facility should not be held liable for PRD releases or smoking flares during these events. A commenter argued that considering the difficulty of enforcing the standard is not a rational basis to remove *force majeure* provisions. The commenter also noted the fact that few *force majeure* events were identified indicates that facilities are not abusing the provisions. A commenter stated that removing the *force majeure* provisions could create resource burdens for local authorities if there is an increase in violations.

Response: After consideration of the comments submitted, the EPA is finalizing the revisions as proposed and removing the *force majeure* allowance from the criteria for a violation of the work practice standards for atmospheric PRD releases and emergency flaring events. Commenters indicated that the basis for the EPA's conclusion that the *force majeure* exemption was rarely used was because it only took into consideration three years of data. However, this 3-year period is the period for which the work practice standards were in effect for refineries and thus we believe that this is the best available data from which to draw conclusions on the efficacy and necessity of the elements of the work practice standards (Standards under CAA section 112 are to reflect emissions limitations ''for which the Administrator has emissions information.''). Although some commenters indicate that there were major weather events that could have caused relief events from PRDs or flare smoking events, they did not provide any detailed information on whether any PRD or flare smoking events actually occurred from these weather events.

In addition, as the EPA has consistently explained, in the event that a source fails to comply with the

---

[23] 88 FR 25580 (Apr. 27, 2023).

applicable CAA section 112 standards, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during the violative periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. Thus, while this action removes the *force majeure* provisions from the PRD and emergency flaring work practice standards, the EPA will continue to evaluate violations on a case-by-case basis and determine whether an enforcement action is appropriate. If the EPA determines in a particular case that enforcement action against a source for violation of a standard is warranted, the source can raise any and all defenses in that enforcement action and the federal district court will determine what, if any, relief is appropriate. The same is true for citizen enforcement actions.

Regarding the comment that the work practice standards do not provide continuous standards, we disagree with this comment. We have previously addressed this issue and the EPA's position that the *force majeure* provisions do not make the standards non-continuous has not changed. We addressed this in the preamble to the proposed rule [24] where we explained that we had previously addressed this in a September 2020 letter to Earthjustice (Docket Item No. EPA–HQ–OAR–2010–0682–0999). Components of both the PRD management provisions and emergency flaring provisions apply at all times; not all components of the standard must apply at all times for the standard to be continuous.

Therefore, in this final action for Petroleum Refinery MACT 1, the EPA is removing the *force majeure* allowance from the criteria for a violation of the work practice standard for atmospheric PRD releases and emergency flaring events in 40 CFR 63.648(j)(3) and 63.670(o)(7). We are also amending the reporting requirements for the event-specific work practice standard data in 40 CFR 63.655(g)(10)(iv) and (11)(iv) to require these data to be reported electronically through the EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). As further discussed in section III.G. of this preamble, we are finalizing that the removal of the *force majeure* provisions is effective 60 days after the effective date of the final rule.

For flares, the EMACT standards and MON cross reference the petroleum refinery flare provisions at 40 CFR 63.670. Therefore, the revisions to 40 CFR 63.670(o)(7) for emergency flaring events are incorporated into the requirements for these regulations.

The EPA is also revising the EMACT standards and the MON consistent with our proposal. We are removing the *force majeure* allowance from the criteria for a violation of the work practice standard for atmospheric PRD releases in 40 CFR 63.1107(h)(3) and 63.2480(e)(3) going forward. However, we are not removing the term *force majeure* from the list of defined terms in 40 CFR 63.1103(e)(2) and 63.2550. As further discussed in section III.G. of this preamble, we are finalizing that the removal of the *force majeure* provisions is effective 60 days after the effective date of the final rule. Lastly, the EPA is finalizing new reporting requirements for the EMACT standards at 40 CFR 63.1110(a)(10)(iii) to require electronic reporting, through the CDX using CEDRI, of the event-specific work practice standard data in 40 CFR 63.1110(e)(4)(iv) and 63.1110(e)(8)(iii). We note that the MON already has a more general compliance report template for electronic reporting, see 40 CFR 63.2520(e), which will automatically incorporate electronic reporting of the event-specific work practice standard data.

B. Storage Vessel Degassing

Topic summary: The EMACT standards, OLD NESHAP, and MON currently include a work practice standard for storage vessel degassing to control emissions from shutdown operations (see 40 CFR 63.1103(e)(10), 40 CFR 63.2346(a)(6), and 40 CFR 63.2470(f), respectively). An opportunity to comment on the storage vessel degassing provisions was not previously provided because, based on comments received for all three rules, the provisions were included in the final 2020 rules but not in the rules proposed in 2019. Therefore, the EPA re-proposed in 2023 what was finalized for each rule in 2020. The EPA also proposed additional revisions based on petitioners' arguments to address degassing of floating roof storage vessels. The requirements, as finalized in the 2020 rules, allow storage vessels to be vented to the atmosphere once a storage vessel degassing concentration threshold is met (*i.e.,* less than 10 percent of the lower explosive limit (LEL)) and all standing liquid has been removed from the vessel to the extent practicable. The requirements are applicable to all storage vessels (regardless of roof type) that are subject to control requirements in each of the rules. We based the degassing standard on Texas permit conditions, which represented the MACT floor.[25] Specifically, permit condition 6 (applicable to floating roof storage vessels) and permit condition 7 (applicable to fixed roof storage vessels) formed the basis of the storage vessel degassing standard.

The petitioners stated that while they did identify the Texas permit conditions as a reference in their comments to the 2019 proposed rules, certain key information was not incorporated into the final 2020 EMACT standards, OLD NESHAP, and MON for the degassing of floating roof storage vessels. Additionally, the petitioners argued that they did not request additional work practices for floating roof storage vessels for which owners and operators already elect to comply with the floating roof storage vessels requirements in 40 CFR part 63, subpart WW because, even with the removal of the shutdown exemption, the petitioners contended that it is still possible to comply with the subpart WW provisions.

The EPA disagreed with the petitioners' claims that a separate standard for floating roof storage vessel degassing is not needed due to the removal of the shutdown exemption. Rather, we determined that we must set a storage vessel degassing standard that applies to storage vessels under CAA section 112. We also determined that storage vessel degassing is a unique shutdown activity with operations and emissions that are completely different from normal storage vessel operations, and 40 CFR part 63, subpart WW does not address degassing emissions from floating roof storage vessels.

Because the EPA determined that a standard is necessary for degassing of all storage vessels (regardless of roof type), the EPA reviewed the Texas permit conditions again to determine if revisions to the degassing standard for floating roof storage vessels in the EMACT standards, OLD NESHAP, and MON are appropriate. Based upon this review, we proposed and are now finalizing that a floating roof storage vessel may be opened prior to degassing to set up equipment (*i.e.,* make connections to a temporary control device), but this must be done in a limited manner and operators must not actively purge the storage vessel while connections are made. See section III.B. of the preamble to the proposed rule for additional details on the storage vessel degassing revisions.[26]

---

[24] 88 FR 25574, 25580 (Apr. 27, 2023).

[25] Texas Permit Conditions are available at: *https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/mss/chem-mssdraftconditions.pdf.*

[26] 88 FR 25581 (Apr. 27, 2023).

Comments: Several commenters supported the storage vessel degassing requirements in the 2023 proposal, including having a separate requirement for floating roof storage vessels. However, some commenters requested clarification on certain aspects of the rule text. A commenter requested clarification on whether the phrase ''must not be actively degassed'' (from the rule text) and ''not actively purge'' (from the preamble) have the same meaning for floating roof storage vessels. The commenter also requested confirmation that breathing emissions following a floating roof landing and before commencing degassing operations are not a deviation of the standard. A commenter stated that not providing a timeframe for degassing creates ambiguity and encouraged the EPA to use the same 24-hour window as the Texas permit conditions for consistency. Another commenter recommended the EPA incorporate a requirement based on the maintenance vent standard, which would allow active purging if the pressure in the storage vessel is 2 pounds per square inch gauge or less. A commenter recommended that the EPA incorporate additional recordkeeping and reporting requirements for storage vessel degassing, such as recording and reporting information from the vapor space concentration measurements. A commenter also requested the EPA further define degassing.

Response: After consideration of the comments submitted, we are finalizing the storage vessel degassing requirements as proposed, including the separate requirement for floating roof storage vessels. We do confirm that the phrase ''must not be actively degassed'' (from the rule text) and ''not actively purge'' (from the preamble) have the same meaning for purposes of the floating roof storage vessel degassing provisions. We are also aware that the Texas permit condition 6.B provides a 24-hour window to start controlled degassing after the floating roof storage vessel has been drained, and that the storage vessel may be opened during this period only to set up for degassing and cleaning. However, we determined at proposal that the 24-hour window stipulates how long a floating roof storage vessel can be landed before it needs to be filled again or degassed, but it does not have a direct bearing on the underlying control standard for degassing operations. As such, we are not revising the final rule to incorporate the 24-hour window into the storage vessel degassing standard.

We agree with the commenter that emissions as a result of vapor space expansion (*i.e.,* breathing emissions) following landing of a floating roof and prior to commencing degassing operations do not constitute a bypass or deviation of the standards. We note that this work practice standard for storage vessel degassing applies ''during storage vessel shutdown operations (*i.e.,* emptying and degassing of a storage vessel).''

We also do not agree that incorporating a requirement similar to the maintenance vent standard is appropriate for storage vessel degassing. The intent of the standard is to control degassing emissions to the level of the MACT floor, which in this case is the use of controls to minimize emissions until the vapor space concentration reaches 10 percent of the LEL.

We do not believe that additional clarity on the definition of degassing is warranted as this process is well understood. Storage vessel degassing has always been in the rules as part of the definition of ''Shutdown'' (*i.e.,* Shutdown also applies to emptying and degassing storage vessels). In addition, there have been many commenters on each of the rules over the past four years providing feedback regarding storage vessel degassing; during this time no clarifications regarding the definition of degassing were needed.

We are finalizing clarifications to the storage vessel degassing standards for the EMACT standards at 40 CFR 63.1103(e)(10), the OLD NESHAP at 40 CFR 63.2346(a)(6), and the MON at 40 CFR 63.2470(f).

We also want to clarify that the overlap provisions in the MON and OLD NESHAP for storage vessels do not apply with respect to demonstrating compliance with the storage vessel degassing standards.[27] While these overlap provisions (*e.g.,* 40 CFR part 60, subpart Kb; 40 CFR part 61, subpart Y) do include storage vessel standards that facilities subject to the MON and OLD NESHAP may comply with for storage vessels during normal operation, they do not include an equivalent alternative standard to the storage vessel degassing standards that were finalized in 2020 and that are being clarified in this final action. As such, facilities subject to the MON and OLD NESHAP must always comply with the storage vessel degassing standards included therein even if complying with these overlap provisions.

C. Other EMACT Standards Technical Corrections and Clarifications

The EPA is finalizing additional revisions for the EMACT standards that address other technical corrections and clarifications and correct typographical errors. We received comments on some of the revisions that were proposed for the EMACT standards. In this section, we provide comment summaries and responses for the EMACT standards topics where comments were received. We also include revisions to the EMACT standards that were not proposed but for which commenters provided technical clarifications to the rule and the EPA is finalizing. Table 2 of this preamble shows the revisions to the EMACT standards for which no comments were received, and that the EPA is finalizing as proposed. Although we briefly summarize these items below, refer to section III.C.1. of the preamble to the proposed rule for additional details.[28]

Topic summary, delay of burner repair provisions (40 CFR 63.1103(e)(7)(i)): A petitioner argued that requiring an ethylene cracking furnace to implement the delay of burner repair provisions finalized in the 2020 final rule is impracticable and is inconsistent with what the best performers are doing. The petitioner stated that a significant amount of preparation is needed to shutdown an ethylene cracking furnace and that no source can comply with the delay of burner repair provisions as written. Accordingly, where a burner cannot be repaired without an ethylene cracking furnace shutdown, owners or operators would have to decoke their ethylene cracking furnaces immediately (*i.e.,* within 1 day of identifying flame impingement), leading to more decoking events and subsequently more emissions from the decoking of ethylene cracking furnaces.

An opportunity to comment on the delay of burner repair provisions was not previously provided because the provisions were included in the final 2020 rule but not in the 2019 proposed rule. Therefore, the EPA re-proposed at 40 CFR 63.1103(e)(7)(i) what was finalized along with the following revisions for delay of burner repair.

The EPA proposed to remove the requirement that the owner or operator may only delay burner repair beyond 1 calendar day if a shutdown for repair would cause greater emissions than the potential emissions from delaying repair. We agreed that this requirement

---

[27] The EMACT standards require owners or operators to comply specifically with the EMACT standards where overlap may exist for various storage vessel control requirements (see 40 CFR 63.1100(g)(1)); thus, it is not necessary to clarify that the storage vessel degassing standards always apply in this NESHAP.

[28] 88 FR 25582 (Apr. 27, 2023).

if left in place would lead to more decoking events and more emissions from decoking of ethylene cracking furnaces. Instead of evaluating emissions to determine whether delay of repair is allowed, the EPA proposed that delay of repair beyond 1 calendar day is allowed if the repair cannot be completed during normal operations, the burner cannot be shutdown without significantly impacting the furnace heat distribution and firing rate, and action is taken to reduce flame impingement as much as possible during continued operation. We also maintained that if a delay of repair is required to fully resolve burner flame impingement, repair must be completed following the next planned decoking operation (and before returning the ethylene cracking furnace back to normal operation) or during the next ethylene cracking furnace complete shutdown (when the ethylene cracking furnace firebox is taken completely offline), whichever is earlier.

Comments: A few commenters supported the proposed revision to the ethylene cracking furnace delay of burner repair requirements. They indicated that the proposed language provided needed flexibility. However, some of the commenters recommended additional revisions to the language to add specificity regarding when burner repair is allowed. Specifically, the commenters asked for an allowance to delay repairs until the next planned shutdown if a complete furnace shutdown is required to complete the repair.

Response: We disagree with the commenters that additional allowances for burner repair are warranted and are finalizing the revisions as proposed. We proposed the revisions to the delay of repair language to provide flexibility and acknowledge the industry's general practice for burner inspection and repair. However, allowing facilities to protract burner repair to a further point in time, which may be years in the future for the next ethylene cracking furnace complete shutdown, goes against the purpose of the burner inspection and repair provisions which is to stop flame impingement and minimize decoking emissions. Additionally, the decoking of ethylene cracking furnaces has always been included in the definition of *Shutdown* in the regulatory text of the EMACT standards and has always been considered a shutdown operation. The EPA is finalizing the delay of burner repair provisions as proposed and owners or operators must repair the burner following the next decoking event or complete shutdown, whichever is earlier.

Topic summary, isolation valve inspection and repair (40 CFR 63.1103(e)(8)(i)): A petitioner requested that the EPA revise the requirement to rectify poor isolation prior to continuing decoking operations. The petitioner argued that certain isolation valve repairs must be completed after the ethylene cracking furnace is shutdown, which consequently requires decoking the ethylene cracking furnace. The petitioner said that if a furnace is not decoked prior to shutdown, damage can occur to the furnace tubes and could pose a safety issue. In addition, the petitioner noted that some isolation valves serve gas streams from multiple ethylene cracking furnaces, and there may be instances when all furnaces would need to be decoked and shutdown to properly rectify the isolation valve issue. The petitioner argued that allowing for some flexibility is necessary for facilities to operate properly and to avoid damaging equipment.

We agreed with the petitioner and proposed language at 40 CFR 63.1103(e)(8)(i) to allow facilities to wait and rectify isolation valve issues after a decoking operation, provided that the owner or operator can reasonably demonstrate that damage to the radiant tube(s) or ethylene cracking furnace would occur if the repair was attempted prior to completing a decoking operation and/or prior to the ethylene cracking furnace being shutdown.

Comments: Some commenters supported the proposed revision to the ethylene cracking furnace isolation valve inspection and repair requirements. They indicated that the proposed language was consistent with industry practices. The commenters also recommended additional revisions to emphasize that the company must be able to make the determination regarding whether to delay repair if the radiant tubing or ethylene cracking furnace could be damaged.

Response: The EPA acknowledges the commenters' support and is revising the proposed language in response to the comments. We agree that the owner or operator does not need to directly demonstrate to the regulating authority that damage would occur to the radiant tubes or ethylene cracking furnace before using the allowance to delay repair. We are clarifying in 40 CFR 63.1103(e)(8)(i) that the owner or operator can make the determination that damage could occur in order to avail themselves of this delay of repair allowance.

Topic summary, removal of electronic reporting requirements (40 CFR 63.1100(b), 63.1103(e)(4)(iii), and 63.1110(a)(10)(i), (ii), (iii), and (iv)): Instructions for submitting reports electronically through CEDRI, including instructions for submitting CBI and asserting a claim of EPA system outage or *force majeure,* were recently added to 40 CFR 63.9(k);[29] therefore, text related to these requirements was no longer necessary in the EMACT standards. As such, we removed duplication and pointed directly to 40 CFR 63.9(k) when required to submit certain reports to CEDRI.

Comment: A commenter agreed with the revisions to point to 40 CFR 63.9(k) directly, but also stated that an additional reference to this citation is warranted in 40 CFR 63.1100(b).

Response: We agree with the commenter and are referencing 40 CFR 63.9(k) in the last sentence of 40 CFR 63.1100(b). We are also finalizing the edits at 40 CFR 63.1103(e)(4)(iii) and 63.1110(a)(10)(i), (ii), (iii), and (iv), as proposed.

Topic summary, LEL clarification (40 CFR 63.1103(e)(5), 63.1103(e)(10), 63.1109(f), 63.1110(e)(5)): These provisions reference the term ''LEL'' for the purposes of determining compliance. We did not propose revisions for this term, but commenters provided feedback stating that it was being misused.

Comments: Commenters stated that we were misusing the term LEL in certain rule provisions for maintenance vents and storage vessel degassing (*e.g.,* 40 CFR 63.1103(e)(5), 40 CFR 63.1103(e)(10)). Commenters stated the LEL was a fixed physical property of a vapor mixture and thus, is neither changed nor measured. According to commenters, LEL refers to a specific concentration value for a particular mixture. For example, when opening a maintenance vent, commenters elaborated that you measure the concentration of the vapor and then you can compare that concentration to the LEL. The commenter thought the rule text incorrectly implied that you measured the LEL of the vapor. The commenters requested that the EPA clarify that the concentration of the vapors in equipment for maintenance vents (and the vapor space concentration for storage vessel degassing) must be less than 10 percent of the LEL and that facilities are to measure the concentration, not the LEL.

Response: We agree with commenters that the rule text referring to the LEL was used incorrectly for certain

---

[29] 85 FR 73885 (Nov. 19, 2020).

maintenance vent and storage vessel degassing provisions and that the LEL cannot be changed for a vapor. We are revising the rule text to make clear that facilities measure the vapor concentration and then compare that concentration value to the LEL of the vapor to determine if the concentration is less than 10 percent of the LEL.

TABLE 2—SUMMARY OF REVISIONS TO 40 CFR PART 63, SUBPART YY FOR WHICH THE EPA RECEIVED NO COMMENT

Provision	Issue summary	Final revision
40 CFR 63.1110(e)(4)(iii)	Provision contains a typographical error.	The EPA is replacing "§ 63.1109(e)(7)" with "§ 63.1109(e)(6)" to correct the typographical error.
40 CFR 63.1102(c)(11), (d)(2)(ii), and (e)(2)(iii).	Provisions contain a typographical error.	The EPA is replacing "§ 63.1108(a)(4)(i)" with "§ 63.1108(a)(4)" to correct a typographical error that we made while removing startup, shutdown, and malfunction exemptions.

D. Other OLD NESHAP Technical Corrections and Clarifications

There are additional revisions that we are finalizing for the OLD NESHAP to address other technical corrections and clarifications and to correct typographical errors. We did not receive comments on all of the revisions that were proposed for the OLD NESHAP. Table 3 of this preamble shows the revisions to the OLD NESHAP for which no comments were received and the EPA is finalizing as proposed. Table 4 of this preamble shows revisions to the OLD NESHAP which were not proposed but where commenters provided technical clarifications to the rule, which the EPA is finalizing. Refer to section III.C.2. of the preamble to the proposed rule for additional details.[30]

TABLE 3—SUMMARY OF REVISIONS TO 40 CFR PART 63, SUBPART EEEE FOR WHICH THE EPA RECEIVED NO COMMENT

Provision	Issue summary	Final revision
40 CFR 63.2346(a)(6)	Provision contains a typographical error	The EPA is replacing "items 3 through 6 of table 2 to this subpart" with "items 2 through 6 of table 2 to this subpart" to correct the typographical error.
40 CFR 63.2346(e)	Provision contains a typographical error	The EPA is replacing "storage vessels" with "storage tanks" to correct the typographical error.
40 CFR 63.2378(e)(3)	Provision needing technical clarifications	The EPA is adding the word "planned" in front of "routine maintenance" in the last sentence of the provision in order to further clarify the provision only applies to periods of planned routine maintenance. We are also replacing "storage vessel" with "storage tank" in the last sentence of the provision to correct a typographical error.
40 CFR 63.2378(e)(4)	Provision needing technical clarifications	To create consistency in the time period during which the bypass provision applies (*i.e.,* the level of material in the storage vessel must not be increased during the same time period that breathing loss emissions bypass the fuel gas system or process), we are deleting "to perform routine maintenance" from the last sentence of 40 CFR 63.2378(e)(4). We are also replacing "storage vessel" with "storage tank" in the last sentence of the provision to correct a typographical error.
40 CFR 63.2382(d)(3); 63.2386(f), (g), (h), (i), and (j); and 63.2406.	Provisions needing technical clarifications or removal	The EPA is removing duplication and pointing directly to 40 CFR 63.9(k) when required to submit certain reports to CEDRI. Specifically, instructions for submitting reports electronically through CEDRI, including instructions for submitting CBI and asserting a claim of EPA system outage or *force majeure,* were recently added to 40 CFR 63.9(k) (85 FR 73885; November 19, 2020); therefore, text related to these requirements was no longer necessary in the OLD NESHAP.

---

[30] 88 FR 25584 (Apr. 27, 2023).

TABLE 4—SUMMARY OF REVISIONS TO 40 CFR PART 63, SUBPART EEEE THAT WERE NOT PROPOSED BUT ARE BEING FINALIZED BASED ON COMMENTER INPUT

Provision	Issue summary	Final revision
40 CFR 63.2346(a)(6)	In comments on the EMACT standards, MON, and Petroleum Refinery MACT 1, commenters stated that we were misusing the term LEL in certain rule language provisions for maintenance vents and storage vessel degassing. See the comment summary and response in section III.C. of this preamble for additional details.	While commenters did not specifically point out revisions to the OLD NESHAP, we are finalizing revisions to 40 CFR 63.2346(a)(6) for consistency. Specifically, we are clarifying that the owner or operator must determine the concentration of the vapor space as opposed to determining the LEL of the vapor space.
Table 12 to Subpart EEEE of Part 63.	Provisions needing technical clarifications	40 CFR 63.7(a)(4) is not cited in the general provisions applicability table. We are referencing 40 CFR 63.7(a)(4) in this table and stating it applies to the OLD NESHAP.

E. Other MON Technical Corrections and Clarifications

This section of the preamble presents revisions we are finalizing to the MON heat exchange system requirements along with additional revisions that we are finalizing for the MON to address other technical corrections and clarifications and to correct typographical errors. We did not receive comments on some of the revisions that were proposed for the MON. In this section, we provide comment summaries and responses for the MON topics where comments were received. We also include revisions to the MON which were not proposed but where commenters provided technical clarifications to the rule, which the EPA is finalizing. Following this, table 5 of this preamble shows the revisions to the MON for which no comments were received, and the EPA is finalizing as proposed. We briefly summarize these items below; see section III.C.3. of the preamble to the proposed rule for additional details.[31]

Topic summary, leak monitoring requirements for heat exchange systems with soluble HAP (40 CFR 63.2490(e)): In May 2021, EPA Region 4 received a request from Eastman Chemical Company to perform alternative monitoring instead of the Modified El Paso Method to monitor for leaks in Eastman's Tennessee Operations heat exchange systems, which primarily have cooling water containing soluble HAP with a high boiling point (see Docket Item No. EPA–HQ–OAR–2022–0787–0028). Eastman requested that the previous water sampling requirements for heat exchange system leaks provided in the MON, which ultimately references 40 CFR 63.104(b) (*i.e.,* use of any EPA-approved method listed in 40 CFR part 136 as long as the method is sensitive to concentrations as low as 10 parts per million (ppm) and the same method is used for both entrance and exit samples), be allowed for cooling water containing certain soluble HAP in lieu of using the Modified El Paso Method. Eastman specifically identified two HAP, 1,4-dioxane and methanol, which do not readily strip out of water using the Modified El Paso Method. Eastman's application for alternative monitoring included experimental data showing that the Modified El Paso Method would likely not identify a leak of these HAP in heat exchange system cooling water. Based upon a review of the information provided by Eastman, we proposed that water sampling of heat exchange systems may be used but only if 99 percent by weight or more of all the organic compounds that could potentially leak in the cooling water have a Henry's Law Constant less than a certain threshold (*i.e.,* 5.0E–6 atmospheres per mole per cubic meter (atm-m^3/mol) at 25° Celsius). See section III.C.3. of the preamble to the proposed rule for additional details.[32]

Comments: Some commenters supported the proposed revisions to allow for water sampling of heat exchange systems, instead of the Modified El Paso Method, in limited instances. However, each of the commenters also argued that the EPA must revise the proposed language to add specificity regarding the compounds for which the water sampling alternative could be used. The commenters stated that the requirement should only apply to heat exchange systems with 99 percent by weight or more of organic HAP compounds that meet certain thresholds instead of just 99 percent by weight or more of organic compounds that meet certain thresholds. The commenters contended that because the rule serves to identify leaks of HAP, specifying that the threshold applies only to organic HAP is necessary. The commenters were concerned the proposed revisions could lead to expenditures fixing leaks that do not contain HAP. A commenter also requested the EPA clarify whether small heat exchange systems with a cooling water flow rate of 10 gallons per minute or less are required to use the Modified El Paso Method.

Response: After considering the comments submitted, the EPA is finalizing the monitoring revisions as proposed to allow for water sampling of heat exchange systems in limited instances. We disagree with the commenters' request to revise the language to specify "HAP" compounds for the 99 percent by weight requirement. The proposed revisions do not impact what heat exchangers are subject to monitoring; rather they help determine what type of monitoring is allowed (*i.e.,* Modified El Paso Method or water sampling), and the existing language already includes specificity regarding HAP compounds. The definition of heat exchange system states that the heat exchange system must be in organic HAP service (*i.e.,* contain at least 5 percent by weight of total organic HAP) in order to be subject to the heat exchange system monitoring requirements. Additionally, 40 CFR 63.104(b) is clear that owners and operators must monitor for "the presence of one or more organic hazardous air pollutants or other representative substances whose presence in cooling water indicates a leak." The introductory text of 40 CFR 63.2490(e), which says: "you may monitor the cooling water for leaks according to the requirements in § 63.104(b) in lieu of using the Modified El Paso Method," is also only intended to specify what type of monitoring is required.

Regarding small heat exchange systems with a cooling water flow rate of 10 gallons per minute or less, we believe that further clarification to the rule is not needed. The 10 gallons per

---

[31] 88 FR 25584 (Apr. 27, 2023).

[32] 88 FR 25584 (Apr. 27, 2023).

minute threshold provided in 40 CFR 63.2490(d) only applies to the Modified El Paso Method monitoring requirements in 40 CFR 63.2490(d). As such, heat exchange systems with a cooling water flow rate of 10 gallons per minute or less are still subject to the requirements of 40 CFR 63.104, as they have been historically, and must continue complying as they always have.

In summary, the EPA is finalizing at 40 CFR 63.2490(e) that the leak monitoring requirements for heat exchange systems at 40 CFR 63.104(b) may be used in limited instances (*i.e.,* if 99 percent by weight or more of all the organic compounds that could potentially leak into the cooling water have a Henry's Law Constant less than 5.0E–6 atmospheres per mole per cubic meter (atm-m^3/mol) at 25° Celsius) instead of using the Modified El Paso Method to monitor for leaks. While we are finalizing that the leak monitoring and leak definition requirements at 40 CFR 63.104(b) may be used in limited instances, we did not propose nor finalize that other provisions of 40 CFR 63.104 apply. Instead, for example, facilities that use water sampling to detect leaks must still comply with the recordkeeping and reporting requirements of 40 CFR 63.2520(e)(16) and 40 CFR 63.2525(r). We are finalizing revisions at 40 CFR 63.2520(e)(16) and 40 CFR 63.2525(r) to specify this.

Topic summary, PRDs with rupture disks (40 CFR 63.2480(e)(2)(ii) and (e)(2)(iii)): For PRDs with rupture disks, a petitioner pointed out that EPA agreed in their response to comment document (see docket item EPA–HQ–OAR–2018–0746–0200 in the MON RTR docket) to delete the second sentence (*i.e.,* the requirement to conduct monitoring if rupture disks are replaced) from 40 CFR 63.2480(e)(2)(ii) and (e)(2)(iii). However, the final rule (85 FR 49084, August 12, 2020) did not reflect these deletions. We agreed that the language diverges from what 40 CFR part 63, subpart UU required for PRDs. Therefore, we proposed to correct this error by deleting the second sentence from 40 CFR 63.2480(e)(2)(ii) and (e)(2)(iii).

Comments: A commenter supported the proposed revision to the monitoring requirements for PRDs with rupture disks and stated the revision provides consistency with other rules.

Response: The EPA acknowledges the commenter's support, and we are finalizing the revisions as proposed.

Topic summary, scrubber testing and monitoring requirements (40 CFR 63.2493(a)(2)(vi) and (b)(4)): A petitioner requested clarification of scrubber monitoring parameters and the types of scrubbers that are applicable to certain requirements at 40 CFR 63.2493(a)(2)(vi) and (b)(4). The petitioner stated that the rule is only applicable to scrubbers that use an acid solution and reactant tank, but that other types of scrubbers are used in instances when ethylene oxide is present in small amounts. The petitioner requested the pH monitoring parameter be revised to account for other types of scrubbers. The petitioner also requested the temperature of the ''scrubber liquid'' be monitored instead of the temperature of the ''water.''

Scrubbers that use an acid solution and reactant tank are the primary focus of the scrubber monitoring requirements because this type of scrubber liquid is necessary to specifically control ethylene oxide. As such, we did not propose to revise the monitoring parameters to apply more broadly, such as to scrubbers that use water as the scrubbing liquid. We proposed clarifying language that the monitoring requirements at 40 CFR 63.2493(a)(2)(vi) and (b)(4) are applicable to scrubbers ''with a reactant tank.'' We agreed with the petitioner regarding temperature monitoring and proposed a correction that the temperature of the ''scrubber liquid'' must be monitored. We also proposed clarifying language at 40 CFR 63.2493(a)(2)(viii) and (b)(6), that if a facility uses a scrubber without a reactant tank that provides control of ethylene oxide, the facility may establish site-specific operating parameters.

Comments: Commenters supported the proposed revision to the scrubber testing and monitoring requirements for scrubbers controlling ethylene oxide. In addition, a commenter recommended that the EPA only allow scrubbers with reactant tanks and acid solutions to control ethylene oxide. Another commenter also requested that the EPA allow any scrubber to control ethylene oxide by developing site-specific operating parameters, regardless of the amount of control the scrubber provides. This commenter stated they understood the proposal allows for site-specific operating parameters only if the scrubber provides incidental control of ethylene oxide.

Response: We acknowledge the commenters' support and are finalizing the revisions as proposed. The EPA notes that in the proposed regulatory text changes for the MON, we did not use the phrase ''incidental control.'' We are clarifying provisions at 40 CFR 63.2493(a)(2)(viii) and (b)(6), which would allow an owner or operator who uses a scrubber without a reactant tank to request appropriate operating parameters from the Administrator. In the preamble of the proposed rule, we noted that this option would be available to facilities using scrubbers for incidental control, because it is likely that a scrubber needing to control a significant quantity of ethylene oxide emissions would need to be equipped with a reactant tank. It is unlikely that a water scrubber could provide adequate control of significant ethylene oxide emissions.

Consistent with our long-standing approach of allowing regulated industries to determine how to meet numeric emission limits, the EPA is not requiring the use of acid scrubbers for the control of ethylene oxide. Currently, scrubbers with acid solutions are likely the only scrubber technology that can achieve significant control of ethylene oxide; however, we also acknowledge that there are some facilities with ethylene oxide emissions that are very low and almost meet the outlet concentration limit without control. These owners and operators should be able to use any control device that can allow them to achieve the emission standard. Additionally, there could be a development of new scrubbing technologies for ethylene oxide in the future that use a configuration other than acid solutions and a reactant tank. We do not want to limit the development of these technologies by limiting the control devices that owners and operators must use.

Topic summary, storage tank ethylene oxide concentration (40 CFR 63.2492(b)): A petitioner requested that an alternative to sampling and analysis of storage tank materials should be allowed, to determine if a storage tank is in ethylene oxide service. The petitioner stated that information already exists for some storage tanks to show that the ethylene oxide concentration in the material stored is less than 0.1 percent by weight (sometimes significantly so) and that it is unnecessary to require sampling and analysis. We agreed with the petitioner and proposed to amend 40 CFR 63.2492(b) to allow calculations to be performed to show that the ethylene oxide concentration is less than 0.1 percent by weight of the material stored in the storage tank, provided the calculations rely on information specific to the material stored. This may include using, for example, specific concentration information from safety data sheets.

Comments: Commenters supported the proposed revision to allow calculations to determine the ethylene oxide concentration of the fluid stored in a storage tank. A commenter also recommended that the EPA expand this requirement and allow the use of engineering judgement and process knowledge to determine the concentration, similar to what is allowed to determine the ethylene oxide content for equipment leaks.

Another commenter did not support the proposed revision to allow calculations to determine the ethylene oxide concentration of the fluid stored in a storage tank. The commenter argued that calculations introduce uncertainty and are often underestimated.

A commenter also noted that proposed 40 CFR 63.2492(b)(i) and (b)(ii) should be renumbered to 40 CFR 63.2492(b)(1) and (b)(2).

Response: We are finalizing the revisions to allow calculations to determine the ethylene oxide concentration of the fluid stored in a storage tank as proposed. We disagree with the commenter's request to add more flexibility to the alternative approach in 40 CFR 63.2492(b)(2) for storage tanks to be consistent with the equipment leaks provision at 40 CFR 63.2492(c)(2). The rule is already clear regarding determining whether storage tanks are ''in ethylene oxide service.'' In order to determine the requirements for storage tanks in ethylene oxide service, facilities must look at both the definition of ''in ethylene oxide service'' and the requirements in 40 CFR 63.2492 together. The definition of ''in ethylene oxide service'' lets the owner or operator designate a storage tank based on process knowledge; however, if an owner or operator wants to say a storage tank is not in ethylene oxide service, they must use the procedures in 40 CFR 63.2492(b). The rule at 40 CFR 63.2492(b)(2) already explicitly allows for an owner or operator to calculate the concentration of ethylene oxide of the fluid stored in a storage tank if information specific to the fluid stored is available which includes data based on safety data sheets.

We do agree with the commenter that the proposed numbering was incorrect and are finalizing the revisions at 40 CFR 63.2492(b)(1) and (b)(2).

We are also changing the phrasing of ''sampling and analysis is performed as specified in § 63.2492'' to ''the procedures specified in § 63.2492 are performed'' within the definition of ''in ethylene oxide service'' for storage tanks. This language more clearly aligns with the revised requirements at 40 CFR 63.2492(b).

Topic summary, delay of repair provisions for equipment in ethylene oxide service (40 CFR 63.2493(d)(1)(iii) and 63.2493(d)(2)(iii)): A petitioner requested the EPA clarify whether delay of repair provisions apply to equipment in ethylene oxide service. The petitioner noted that in the response to comments for the final rule, the EPA stated that delay of repair provisions do not apply. However, the petitioner further noted the final rule language did not reflect this. We proposed to revise 40 CFR 63.2493(e) to specify that the delay of repair provisions of 40 CFR part 63, subparts H and UU and 40 CFR part 65, subpart F do not apply for all equipment in ethylene oxide service.

Comments: Commenters did not support the proposed revision to remove the delay of repair provisions for equipment in ethylene oxide service. The commenters contended that removing the delay of repair provisions would increase emissions, because the emissions due to shutdowns can be higher than the leak emissions due to invoking delay of repair. This is particularly true if few components are leaking. A commenter emphasized that companies consider both worker safety and emissions when evaluating leaks and noted some companies have ambient air monitors for ethylene oxide. The commenters stated the number of components in ethylene oxide service that leak is low, and that this is supported by data submitted by chemical manufacturing facilities (which are similar to MON facilities) to the EPA which indicated no leaking connectors, valves, or pumps in ethylene oxide service. The commenters also stated the delay of repair provisions provide important flexibility for companies and allow them to operate without disruptions to their operations.

Another commenter supported the proposed revision to remove the delay of repair provisions for equipment in ethylene oxide service.

Response: We partly erred when stating at proposal that the MON included delay of repair provisions for equipment in ethylene oxide service. The final 2020 MON included specific repair requirements for pumps and connectors in ethylene oxide service at 40 CFR 63.2493(d)(1)(iii) and 63.2493(d)(2)(iii), respectively. These requirements stipulated that a leak must be repaired within 15 days after it is detected. No exceptions were provided for the 15-day timeframe, which means there were no exceptions for delay of repair. Other equipment in ethylene oxide service (*e.g.,* valves) do not have ethylene oxide-specific requirements in the MON like connectors and pumps, and it was our intent that delay of repair provisions still apply for this other equipment (*i.e.,* reducing ethylene oxide emissions from connectors and pumps was determined to be necessary for the 2020 rule, and thus delay of repair was not provided for them). As such, we are not revising the MON to exclude delay of repair provisions for equipment other than connectors and pumps in ethylene oxide service and are not finalizing the revision that was proposed at 40 CFR 63.2493(e)(17). We are maintaining the existing requirements at 40 CFR 63.2493(d)(1)(iii) and 63.2493(d)(2)(iii), with one additional revision. We are finalizing a revision that allows for the delay of repair for connectors and pumps in ethylene oxide service if the equipment is isolated from the process and does not remain in ethylene oxide service.

Topic summary, LEL clarification (40 CFR 63.2450(v), 63.2470(f), 63.2520(e)(14), 63.2525(p)): Maintenance vent and storage vessel degassing provisions reference the term LEL to determine compliance. We did not propose revisions to this term, but commenters provided feedback stating it was being misused.

Comments: Commenters stated that we were misusing the term LEL in certain rule language provisions for maintenance vents and storage vessel degassing (*e.g.,* 40 CFR 63.2450(v), 40 CFR 63.2470(f)). Commenters stated the LEL was a fixed physical property of a vapor mixture and thus does not change nor is it measured. It refers to a specific concentration value for a particular mixture. For example, commenters explained that, when opening a maintenance vent, the concentration of the vapor is measured and then compared to the LEL. The rule text incorrectly implied that the LEL of the vapor is measured. The commenters requested that the EPA clarify that the concentration of the vapors in equipment for maintenance vents (and the vapor space concentration for storage vessel degassing) must be less than 10 percent of the LEL and that facilities are to measure the concentration, not the LEL.

Response: We agree with commenters that the rule text referring to the LEL was used incorrectly for certain maintenance vent and storage vessel degassing provisions and that the LEL cannot be changed for a vapor. We are revising the rule text to be clear that facilities measure the vapor concentration and then compare that concentration value to the LEL of the vapor to determine if the concentration is less than 10 percent of the LEL.

TABLE 5—SUMMARY OF REVISIONS TO 40 CFR PART 63, SUBPART FFFF FOR WHICH THE EPA RECEIVED NO COMMENT

Provision	Issue summary	Final revision
40 CFR 63.2450(e)(6)(i)	Provision contains a typographical error	The EPA is replacing the reference to 40 CFR 63.148(h)(3) with a reference to 40 CFR 63.148(i)(3) to correct the typographical error.
40 CFR 63.2450(e)(7)	A petitioner requested that the EPA clarify whether certain adsorber provisions referenced within 40 CFR 63.983 and other related requirements and exceptions (*i.e.,* 40 CFR 63.2470(c)(3), 40 CFR 63.2520(d)(6) and (e)(13), and 40 CFR 63.2525(o)) apply to this paragraph. The petitioner also pointed out that it is not clear whether a supplement to the notification of compliance status (NOCS) report is needed, and if necessary, what information should be provided.	The EPA is clarifying that 40 CFR 63.2470(c)(3), 40 CFR 63.2520(d)(6) and (e)(13), 40 CFR 63.2525(o), and the provisions referenced within 40 CFR 63.983 all apply (in addition to 40 CFR 63.2450(e)(4) and (e)(6)) if facilities reduce organic HAP emissions by venting emissions through a closed-vent system to an adsorber(s) that cannot be regenerated or a regenerative adsorber(s) that is regenerated offsite. We are also clarifying in 40 CFR 63.2450(e)(1) that 40 CFR 63.2450(e)(1) does not apply when complying with 40 CFR 63.2450(e)(7). As part of this clarification, we are also finalizing a new requirement at 40 CFR 63.2520(d)(6) for adsorbers subject to the requirements of 40 CFR 63.2450(e)(7) requiring a supplement to the NOCS report within 150 days after the first applicable compliance date. We are finalizing that the supplement to the NOCS report must describe whether the adsorber cannot be regenerated or is a regenerative adsorber(s) that is regenerated offsite; and specify the breakthrough limit and adsorber bed life that was established during the initial performance test or design evaluation of the adsorber. Finally, we are revising the introduction paragraph of 40 CFR 63.2520 as well as the requirement in 40 CFR 63.2515(d) to update the reference to 40 CFR 63.2520(d)(6).
40 CFR 63.2460(c)(9)	Provision contains a typographical error	The EPA is replacing the phrase "in paragraphs (c)(9)(i) through (vi) of this section" with "in paragraphs (c)(9)(i) through (iv) of this section" to correct the typographical error.
40 CFR 63.2480(a)	Provision contains a typographical error	The EPA is replacing the phrase "For each light liquid pump, valve, and connector in ethylene oxide service" with "For each light liquid pump, pressure relief device, and connector in ethylene oxide service" to correct the typographical error.
40 CFR 63.2480(f)(18)(iii)	Provision contains a typographical error	The EPA is replacing "§ 63.181(b)(2)(i)" with "§ 63.181(b)(3)(i)" to correct the typographical error.
40 CFR 63.2480(f)(18)(vi)	A petitioner contended that the reference to information required to be reported under 40 CFR 63.182(d)(2)(xiv) is too broad and should be more narrowly described as "information in § 63.165(a) required to be reported under 40 CFR 63.182(d)(2)(xiv)" in order to clarify that the reporting requirement is specific to the recently promulgated PRD requirements.	We agree with the petitioner that the provision should be revised to clarify that the reporting requirement is specific to the recently promulgated PRD requirements. Therefore, we are finalizing language that reads "The information in § 63.165(a) required to be reported under 40 CFR 63.182(d)(2)(xiv) is now required to be reported under § 63.2520(e)(15)(i) through (iii)."
40 CFR 63.2480(f)(18)(x)	Provision contains a typographical error	The EPA is replacing "§ 63.1022(a)(1)(v)" with "§ 63.1023(a)(1)(v)" to correct the typographical error.
40 CFR 63.2480(f)(18)(xiii)	A petitioner contended that the reference to information required to be reported under 40 CFR 63.1039(b)(4) is too broad and should be more narrowly described as "information in § 63.1030(b) required to be reported under 40 CFR 63.1039(b)(4)" in order to clarify that the reporting requirement is specific to the recently promulgated PRD requirements.	We agree with the petitioner that the provision should be revised to clarify that the reporting requirement is specific to the recently promulgated PRD requirements. Therefore, we are finalizing language that reads "The information in § 63.1030(b) required to be reported under 40 CFR 63.1039(b)(4) is now required to be reported under § 63.2520(e)(15)(i) and (ii)."
40 CFR 63.2493(b)(2)	A petitioner requested that the EPA include introductory language to clarify that the requirements apply only if the facility chooses to route emissions to a non-flare control device and chooses to comply with the 1 parts per million volume (ppmv) standard via continuous emission monitoring systems (CEMS).	We agree with the petitioner that 40 CFR 63.2493(b)(2) only applies if the facility chooses to route emissions to a non-flare control device and chooses to comply with the 1 ppmv standard via CEMS. Therefore, we are adding introductory text at 40 CFR 63.2493(b)(2) that clarifies this.
40 CFR 63.2493(d)(3)	A petitioner contended that the reference to "affected source" should be revised to "MCPU" to be consistent with the second column of Table 6 to Subpart FFFF of Part 63.	We agree with the petitioner to revise the provision for consistency with Table 6 to Subpart FFFF of part 63; therefore, we are replacing "affected source" with "MCPU".
40 CFR 63.2493(d)(4)(v)	Provision contains a typographical error	The EPA is replacing "§ 63.2445(h)" with "§ 63.2445(i)" to correct the typographical error.

TABLE 5—SUMMARY OF REVISIONS TO 40 CFR PART 63, SUBPART FFFF FOR WHICH THE EPA RECEIVED NO COMMENT—Continued

Provision	Issue summary	Final revision
40 CFR 63.2520(d)	A petitioner pointed out that the EPA indicated in the preamble to the final rule (85 FR 49084; August 12, 2020) that electronic reporting is required at 40 CFR 63.2520(d) for the NOCS report; however, the final rule does not contain this requirement. The petitioner requested that the EPA clarify that this was a misstatement in the preamble language and that the NOCS report is not required to be submitted electronically.	We acknowledge there was an inconsistency in what we said in the preamble about electronic reporting NOCS reports versus what we required in the 2020 final rule. However, the inconsistency is irrelevant because in this rulemaking, we are finalizing at 40 CFR 63.2520(d) to require NOCS reports be submitted electronically through the EPA's CDX CEDRI. The requirement to submit NOCS reports electronically will increase the ease and efficiency of data submittal and data accessibility.
40 CFR 63.2525(o)	A petitioner requested that the EPA update the recordkeeping requirements for adsorbers that cannot be regenerated and for regenerative adsorbers that are regenerated offsite to reflect the monitoring requirements in the final rule (85 FR 49084; August 12, 2020). Specifically, the petitioner requested that the EPA revise 40 CFR 63.2525(o)(1) to require that you must keep records of the breakthrough limit and bed life for each adsorber established according to 40 CFR 63.2450(e)(7)(i); revise 40 CFR 63.2525(o)(2) to require that you keep records of each outlet HAP or TOC concentration measured according to 40 CFR 63.2450(e)(7)(ii) and (e)(7)(iii); and revise 40 CFR 2525(o)(3) to require records of the date and time each adsorber is replaced. The petitioner also requested the EPA remove the requirement at 40 CFR 63.2525(o)(4) in its entirety.	In the 2020 final rule, we inadvertently did not revise the recordkeeping requirements to reflect the associated monitoring requirements in 40 CFR 63.2450(e)(7) (for adsorbers that cannot be regenerated and for regenerative adsorbers that are regenerated offsite). We are correcting this by revising 40 CFR 63.2525(o)(1) and (2) and removing the requirement at 40 CFR 63.2525(o)(4) in its entirety, as recommended by the petitioner. However, we are not revising 40 CFR 63.2525(o)(3) as requested by the petitioner. We are keeping the language of 40 CFR 63.2525(o)(3) as-is, which aligns with the language used in 40 CFR 63.2450(e)(7)(iii)(B).
40 CFR 63.2520(e)(2)	Provision contains a typographical error	The EPA is correcting the spelling of "paragraph."
40 CFR 63.2450(e)(5)(iv), 63.2520(e), (f), (g), (h), and (i).	Provisions needing technical clarifications or removal	The EPA is removing duplication and pointing directly to 40 CFR 63.9(k) when required to submit certain reports to CEDRI. Specifically, instructions for submitting reports electronically through CEDRI, including instructions for submitting CBI and asserting a claim of EPA system outage or *force majeure,* were recently added to 40 CFR 63.9(k) (85 FR 73885; November 19, 2020), therefore, text related to these requirements is no longer necessary in the MON.

F. Other Petroleum Refinery MACT 1 Technical Corrections and Clarifications

There are additional revisions that we are finalizing for the Petroleum Refinery MACT 1 to address other technical corrections and clarifications and to correct typographical errors. Refer to section III.C.4. of the preamble to the proposed rule for the additional details.[33]

Issue summary, pressure-assisted flares (40 CFR 63.641, 63.655, and 63.670): We proposed amendments to Petroleum Refinery MACT 1 that are consistent with flaring provisions in other recent rules (*i.e.,* EMACT standards) that adopted the Petroleum Refinery MACT 1 flare requirements but addressed additional issues, such as adding provisions for pressure-assisted flares. The proposed amendments include adding pressure-assisted flares to the definition of the term "flare" in 40 CFR 63.641 and adding appropriate requirements for pressure-assisted flares in 40 CFR 63.670. These amendments are consistent with the EPA's intention that all types of flares, including pressure-assisted flares, are covered by the provisions in Petroleum Refinery MACT 1. The proposed amendments for pressure-assisted flares include pilot flame standards and requirements for cross-lighting in 40 CFR 63.670(b), pressure monitoring in 40 CFR 63.670(d)(3), higher combustion zone operating limits in 40 CFR 63.670(e), and requirements to use only the direct calculation methods for determining the flare vent gas net heating value according to 40 CFR 63.670(l)(5)(ii). We also proposed reporting and recordkeeping requirements specific to pressure-assisted flares in 40 CFR 63.655(g)(11)(iii) and (i)(9)(vi), respectively.

Comment: Two commenters supported the proposed revisions for pressure-assisted flare requirements. A commenter stated the proposed revisions would reduce burden on the regulated facilities, permitting authorities, and the EPA. Another commenter requested clarification on whether existing AMELs would be affected and whether owners and operators could still request an AMEL in the future.

Response: The EPA acknowledges the commenters' support and we are finalizing the revisions as proposed. We confirm that owners and operators can still request an AMEL to demonstrate appropriate flare combustion efficiency, if so desired by an owner or operator. The proposed revisions did not impact the AMEL requirements of 40 CFR 63.670(r). We also confirm that existing AMELs are unaffected by the proposed revisions to the NESHAP requirements.

Topic summary, flare gas composition monitoring requirements (40 CFR 63.671): To provide additional flexibility to the monitoring requirements for flare gas composition as required by 40 CFR 63.670(j), we proposed to add mass spectrometry as a method in 40 CFR 63.671. The current provisions in 40 CFR 63.671 could be interpreted to suggest that gas chromatographs must be used for flare

---

[33] 88 FR 25587 (Apr. 27, 2023).

gas compositional analysis. This was not our intent. We recognize that there are some methods, like mass spectrometry, which can determine flare gas composition without the use of a gas chromatograph. We proposed to add specific requirements for calibration and operation of mass spectrometers that parallel the requirements for gas chromatographs.

Comment: One commenter provided specific rule text edits to multiple provisions within 40 CFR 63.671(e) and (f). The commenter recommended including language specific to ''gas chromatograph'' in 40 CFR 63.671(e); adding reference to the seven-day calibration error test period in 40 CFR 63.671(e)(4); stipulating that net heating value (NHV) calculations must use individual component properties in Table 12 to 40 CFR part 63, subpart CC in 63.671(e)(4)(ii); removing ''without the use of gas chromatography'' in 40 CFR 63.671(f); adding specificity on using low, mid, and high-level calibration gas cylinders in 40 CFR 63.671(f)(2); and revising the calibration requirements for ''net heaving value by mass spectrometer'' in Table 13 to 40 CFR part 63, subpart CC.

Response: First, we noted that there was no difference between the regulatory language from the commenter and the proposed rule revisions for 40 CFR 63.671(e), therefore no changes were considered for this provision.

Next, we considered the commenter recommended revisions to 40 CFR 63.671(e)(4). It appears this suggested revision is intended to clarify that consistent with Performance Specification 9, an initial calibration error test must occur over a 7-day period followed by daily calibration with mid-level calibration standard for each analyte and quarterly performance audits. We have finalized clarifying language in 40 CFR 63.671(e)(4) consistent with our understanding of the commenter's intent as follows, ''The owner or operator must initially determine the average instrument calibration error the during the 7-Day Calibration Error Test Period and subsequently perform daily calibration and quarterly audits using either the compound-specific calibration error method provided in paragraph (i) of this section or using the NHV method provided in paragraph (ii) of this section.''

The commenter also suggested a clarifying edit to the definition of equation term ''NHV measured'' to specify that NHV calculations are to be made based on the individual component properties listed in Table 12. We find that the suggested edit improves clarity that the individual components and respective properties are contained in Table 12 to 40 CFR part 63, subpart CC, and have finalized this edit consistent with the commenter's suggestion.

We are not finalizing any amendments to the proposed new introductory paragraph in 40 CFR 63.671(f) as per the commenter's recommendation to strike ''without the use of gas chromatography.'' This language provides the clarification that the provisions in 40 CFR 63.671(f) are limited in applicability to continuous mass spectrometers that do not use gas chromatography. We are, however, finalizing the commenter's recommended revision to 40 CFR 63.671(f)(2) to add the characterizing language (*i.e.,* low-, mid-, high-) relative to the calibration gas cylinders as this language is consistent with Performance Specification 9 specific in sections 7.1.1–7.1.3.

Finally, we are finalizing the proposed amendments to Table 13 to 40 CFR part 63, subpart CC, as proposed, by cross referencing Performance Specification 9 rather than referring to the requirements in 40 CFR 63.671(e)(4) and (f). Performance Specification 9 includes additional requirements than are listed in 40 CFR 63.671(e)(4) and (f). For example, in section 10.2 of Performance Specification 9, if the instrument average response varies by more than 10 percent of the certified concentration value of the cylinder for an analyte, the owner or operator must immediately inspect the instrument making any necessary adjustments and conduct an initial multi-point calibration in accordance with section 10.1. We intended for affected sources to comply fully with the calibration and quality control requirements in Performance Specification 9 and thus are maintaining the cross reference in Table 13 to 40 CFR part 63, subpart CC.

Topic summary, Alternate Test Method for flare fuel measurements (40 CFR 63.671(e)): The EPA approved an Alternate Test Method to use NHV in place of component heat content (*i.e.,* British thermal units ''BTU'') for select quality control criteria in 40 CFR part 63, subpart CC flare fuel measurements (herein referred to as ALT–131) in December 2018. See 84 FR 7363, 7364 (March 4, 2019).

Comment: The commenter requested that the EPA clarify whether the ability to use this approved Alternate Method 131 is affected by this rulemaking.

Response: We confirm that the approval of ALT–131 will be unaffected by this rulemaking and facilities can continue to utilize ALT–131 for compliance with flare measurement requirements in 40 CFR 63.671(e) and by reference, 40 CFR part 60, appendix B, Performance Specification 9 (PS 9) for determining NHV.

Topic summary, LEL clarification (40 CFR 63.643(c), 63.655(g)(13), 63.655(i)(12)): Maintenance vent provisions reference the term LEL to determine compliance. We did not propose revisions to this term but commenters provided feedback stating it was being misused.

Comments: Commenters stated that we were misusing the term LEL in certain rule language provisions for maintenance vents (*e.g.,* 40 CFR 63.643(c)(1)). Commenters stated the LEL was a fixed physical property of a vapor mixture and thus does not change nor is it measured. It refers to a specific concentration value for a particular mixture. For example, when opening a maintenance vent, commenters elaborated that you measure the concentration of the vapor and then you can compare that concentration to the LEL. The rule text incorrectly implied that the LEL of the vapor is measured. The commenters requested that the EPA clarify that the concentration of the vapors in equipment for maintenance vents must be less than 10 percent of the LEL and that facilities are to measure the concentration, not the LEL.

Response: We agree with commenters that the rule text referring to the LEL was used incorrectly for certain maintenance vent and storage vessel degassing provisions and that the LEL cannot be changed for a vapor. We are revising the rule text to be clear that facilities measure the vapor concentration and then compare that concentration value to the LEL of the vapor to determine if the concentration is less than 10 percent of the LEL.

G. What compliance dates are we finalizing?

We are finalizing new compliance dates for certain revisions to the EMACT standards, OLD NESHAP, MON, and Petroleum Refinery MACT 1. We did not propose new compliance dates for the EMACT standards, OLD NESHAP, and MON because the rules that were promulgated in 2020 had still not come into full effect at the time of proposal in April 2023. The compliance dates were also not stayed as part of this reconsideration action. The compliance dates for the 2020 rules have now passed and owners and operators must have been complying with the EMACT standards by July 6, 2023, the OLD NESHAP by July 7, 2023, and the MON by August 12, 2023. Most of the revisions we are finalizing do not impose substantial new requirements, but rather either provide clarity to the rules for owners and operators or are alternative requirements. As such, we are providing new compliance dates for the EMACT standards, OLD NESHAP, and MON for revisions related to the removal of the *force majeure* provisions only and are not changing the compliance dates for any other revisions to these rules.

For the removal of the *force majeure* provisions from the PRD and emergency flaring work practice standards for each rule and for most actions that we are finalizing for the Petroleum Refinery MACT 1, we are positing that facilities would need some time to successfully accomplish these revisions, including time to read and understand the amended rule requirements; to evaluate their operations to ensure that they can meet the standards during periods of startup and shutdown, as defined in the rule; and to make any necessary adjustments, including adjusting standard operating procedures and converting reporting mechanisms to install necessary hardware and software. The EPA recognizes the confusion that multiple compliance dates for individual requirements would create and the additional burden such an assortment of dates would impose. From our assessment of the timeframe needed for compliance with the revised requirements, the EPA considers a period of 60 days after the effective date of the final rule to be the most expeditious compliance period practicable. Therefore, for the EMACT Standards, OLD NESHAP, MON, and Petroleum Refinery MACT 1, we are finalizing that the *force majeure* provisions shall be fully removed from the PRD and emergency flaring work practice standards as of 60 days after the effective date of the final rule. For the Petroleum Refinery MACT 1, we are also finalizing that affected sources must be in compliance with most other revisions upon initial startup or within 60 days of the effective date of the final rule, whichever is later.

We are finalizing that petroleum refinery owners or operators may comply with the new operating and monitoring requirements for flares upon initial startup or by the effective date of the final rule, whichever is later. We believe that compliance with the flare requirements immediately upon finalizing the rule is necessary to ensure that pressure-assisted flares are appropriately operated.

IV. Summary of Cost, Environmental and Economic Impacts

A. What are the affected facilities?

In our final RTRs, we estimated the following:

There are 26 facilities subject to the EMACT standards that are currently operating and five additional facilities under construction. A complete list of known facilities in the EMACT standards is available in Appendix A of the memorandum, *Review of the RACT/BACT/LAER Clearinghouse Database for the Ethylene Production Source Category* (see Docket Item No. EPA–HQ–OAR–2017–0357–0008 in the EMACT RTR docket).

There are 173 OLD NESHAP facilities currently operating and four additional OLD NESHAP facilities under construction. A complete list of known OLD NESHAP facilities is available in Appendix A of the memorandum, *National Impacts of the 2020 Risk and Technology Review Final Rule for the Organic Liquids Distribution (Non-Gasoline) Source Category* (see Docket Item No. EPA–HQ–OAR–2018–0746–0069 in the OLD NESHAP RTR docket).

There are 201 MON facilities currently operating. A complete list of known MON facilities is available in Appendix 1 of the memorandum, *Residual Risk Assessment for the Miscellaneous Organic Chemical Manufacturing Source Category in Support of the 2019 Risk and Technology Review Proposed Rule* (see Docket Item No. EPA–HQ–OAR–2018–0746–0011 in the MON RTR docket).

Additionally, based on the Energy Information Administration's 2021 Refinery Capacity Report, there are 129 operable petroleum refineries in the United States (U.S.) and the U.S. territories, all of which are expected to be major sources of HAP emissions.

B. What are the air quality impacts?

We did not estimate baseline emissions or emissions reductions for the revisions. None of the revisions have a direct and quantifiable impact on emissions because they are minor revisions to existing requirements.

C. What are the cost impacts?

We expect minimal to no cost impacts due to the revisions. There could be minor costs for affected facilities related to reading the rule, making minor updates to operating procedures in some limited cases, and making minor adjustments to reporting systems. A few revisions provide slightly greater flexibility and could yield minor cost savings. Any potential costs or cost savings are expected to be negligible.

D. What are the economic impacts?

No economic impacts are anticipated due to the revisions because any potential cost impacts are expected to be very minor.

E. What are the benefits?

The proposed revisions are not expected to yield air quality benefits because emissions will not be affected. However, the revisions should improve clarity, monitoring, compliance, and implementation of the rules for the affected source categories.

F. What analysis of environmental justice did we conduct?

The revisions are not expected to impact emissions and therefore we did not conduct an environmental justice analysis. However, environmental justice analyses were conducted for the final 2020 rules for the EMACT standards, OLD NESHAP, and MON.[34]

V. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This action is not a significant regulatory action as defined in Executive Order 12866, as amended by Executive Order 14094, and was therefore not subject to a requirement for Executive Order 12866 review.

B. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under the PRA for the EMACT standards, OLD NESHAP, MON, or the Petroleum Refinery MACT 1. We finalized certain technical revisions, including new electronic reporting provisions for the PRD and emergency flaring work practice standard, but the technical revisions do not result in changes to the information collection burden. The final amendments require facilities to submit the work practice related data using an EPA provided spreadsheet template electronically through CDX using CEDRI. These data would not be expected to also be included in a facility's submission to the delegated State authority and/or EPA Regional Office such that no duplication is expected. The amendments to the mode of reporting of the work practice

---

[34] 85 FR 40415 (Jul. 6, 2020); 85 FR 40757 (Jul. 7, 2020); and 85 FR 49129 (Aug. 12, 2020).

standard-related data are not expected to change the current burden under the PRA and we did not revise the information collection request (ICR) for the rules. The Office of Management and Budget (OMB) has previously approved the information collection activities contained in the existing regulations at 40 CFR part 63, subpart YY and has assigned OMB control number 2060–0489; 40 CFR part 63, subpart EEEE and has assigned OMB control number 2060–0539; 40 CFR part 63, subpart FFFF and has assigned OMB control number 2060–0533; and 40 CFR part 63, subpart CC and has assigned OMB control number 2060–0340.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are already identified in the 2020 final rules for the EMACT standards, OLD NESHAP, MON, and the 2015 final rule for Petroleum Refineries. The amendments to 40 CFR part 63, subparts CC, YY, EEEE, and FFFF would only minimally change the existing requirements for all entities. There could be minor costs for affected facilities related to reading the final rule, making minor updates to operating procedures in some limited cases, and making minor adjustments to reporting systems. A few revisions provide slightly greater flexibility and could yield minor cost savings. Any potential costs or cost savings are negligible.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. While this action creates an enforceable duty on the private sector, the annual cost does not exceed $100 million or more.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have Tribal implications as specified in Executive Order 13175. It will not have substantial new direct effects on Tribal governments, on the relationship between the Federal Government and Indian Tribes, or on the distribution of power and responsibilities between the Federal Government and Indian Tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045 directs federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is not subject to Executive Order 13045 because it is not a significant regulatory action under section 3(f)(1) of Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This rulemaking involves technical standards. The EPA has decided to use Methods 1, 1A, 2, 2A, 2C, 2D, 2F, 2G, 3B, 4, 5, 18, 21, 22, 25, 25A, 27, and 29 of 40 CFR part 60, appendix A; 301, 316, and 320 of 40 CFR part 63, appendix A; and 602 and 624 of 40 CFR part 136, appendix A.

While the EPA identified candidate VCS as being potentially applicable, the Agency decided not to use the VCS identified. The use of voluntary consensus standards for measuring emissions of pollutants or their surrogates subject to emission standards in the rule would not be practical due to lack of equivalency, documentation, validation data and other important technical and policy considerations. Additional information for the VCS search and determinations can be found in the memorandum, *Voluntary Consensus Standard Results for National Emission Standards for Hazardous Air Pollutants: for Ethylene Production, Miscellaneous Organic Chemical Manufacturing, Organic Liquids Distribution (Non-Gasoline), and Petroleum Refineries,* which is available in the docket for this action.

The following standards appear in the amendatory text of this document and were previously approved for the locations in which they appear: SW–846–5031, SW–846–8260D, and SW–846–5030B.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

The EPA believes that this type of action does not concern human health or environmental conditions and therefore cannot be evaluated with respect to potentially disproportionate and adverse effects on communities with environmental justice concerns. As discussed in section IV.F. of this preamble, the revisions are not expected to impact emissions, and thus, no changes to human health or environmental conditions are expected.

Although this action does not concern human health or environmental conditions, the EPA identified and addressed environmental justice concerns when conducting analyses for the final 2020 rules for the EMACT standards, OLD NESHAP, and MON. Further information regarding these environmental justice analyses is available at 85 FR 40415 (July 6, 2020), 85 FR 40757 (July 7, 2020), and 85 FR 49129 (August 12, 2020), respectively.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Incorporation by reference, Reporting and recordkeeping requirements.

Michael S. Regan,
Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency amends part 63 of title 40, chapter I, of the Code of Federal Regulations as follows:

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart CC—National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

■ 2. Amend § 63.641 by revising the entry ''Flare'' to read as follows:

§ 63.641 Definitions.

* * * * *

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, pressure-assisted flares, air-assisted flares, steam-assisted flares, and non-assisted flares.

* * * * *

■ 3. Amend § 63.643 by revising and republishing paragraphs (c)(1) and (2) to read as follows:

§ 63.643 Miscellaneous process vent provisions.

* * * * *

(c) * * *

(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 meeting requirements in paragraphs (a)(1) or (2) of this section, a fuel gas system, or back to the process until one of the following conditions, as applicable, is met.

(i) The concentration of the vapor in the equipment served by the maintenance vent is less than 10 percent of its lower explosive limit (LEL).

(ii) If there is no ability to measure the concentration 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 pounds per square inch gauge (psig) or less. Upon opening the maintenance vent, active purging of the equipment cannot be used until the concentration of the vapors in the maintenance vent (or inside the equipment if the maintenance is a hatch or similar type of opening) is less than 10 percent of its LEL.

(iii) The equipment served by the maintenance vent contains less than 72 pounds of total volatile organic compounds (VOC).

(iv) If the maintenance vent is associated with equipment containing pyrophoric catalyst (*e.g.,* hydrotreaters and hydrocrackers) and a pure hydrogen supply is not available at the equipment at the time of the startup, shutdown, maintenance, or inspection activity, the concentration of the vapor in the equipment must be less than 20 percent of its LEL, except for one event per year not to exceed 35 percent of its LEL.

(v) If, after applying best practices to isolate and purge equipment served by a maintenance vent, none of the applicable criterion in paragraphs (c)(1)(i) through (iv) of this section can be met prior to installing or removing a blind flange or similar equipment blind, the pressure in the equipment served by the maintenance vent is reduced to 2 psig or less. Active purging of the equipment may be used provided the equipment pressure at the location where purge gas is introduced remains at 2 psig or less.

(2) Except for maintenance vents complying with the alternative in paragraph (c)(1)(iii) of this section, the owner or operator must determine the concentration of the vapor or, if applicable, equipment pressure using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications.

* * * * *

■ 4. Amend § 63.648 by revising paragraphs (j)(3)(iv), (j)(3)(v)(B) and (C), (j)(6) introductory text, and (j)(6)(ii) to read as follows:

§ 63.648 Equipment leak standards.

* * * * *

(j) * * *

(3) * * *

(iv) The owner or operator shall determine the total number of release events that occurred during the calendar year for each affected pressure relief device separately. Prior to June 3, 2024, 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) * * *

(B) Prior to June 3, 2024, 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. On and after June 3, 2024, a second release event from a single pressure relief device in a 3 calendar year period for the same root cause for the same equipment.

(C) Prior to June 3, 2024, a third release event not including force majeure events from a single pressure relief device in a 3 calendar year period for any reason. On and after June 3, 2024, a third release event from a single pressure relief device in a 3 calendar year period for any reason.

* * * * *

(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 (iii) of this section.

* * * * *

(ii) Prior to June 3, 2024, 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.

* * * * *

■ 5. Amend § 63.655 by:

■ a. Revising paragraphs (g) introductory text, (g)(10) introductory text, (g)(10)(iv), (g)(11) introductory text, (g)(11)(iii) and (iv), and (g)(13)(iii);

■ b. Adding paragraph (i)(9)(vi); and

■ c. Revising paragraphs (i)(11)(ii), (i)(12)(ii), (i)(12)(iii), (i)(12)(v), and (i)(12)(vi).

The addition and revisions read as follows:

§ 63.655 Reporting and recordkeeping requirements.

* * * * *

(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. The Periodic Report must contain company identifier information (including the company name and address), the beginning and ending dates of the time period covered by the report, and the information specified in paragraphs (g)(1) through (14) of this section, and it must be submitted in accordance with § 63.10(a) of this part. On or after April 4, 2024, upon initial startup, or once the form has been available on the CEDRI website for six months, whichever date is later, owners or operators must submit all subsequent Periodic Reports in accordance with § 63.10(a) of this part except for the items in paragraphs (g)(10)(iv) and (11)(iv) of this section. The items in paragraphs (g)(10)(iv) and (11)(iv) of this section must be submitted using the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart and following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Refinery Sector lead. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

* * * * *

(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 (iv) of this section. Owners or operators must submit the Periodic Report in accordance with § 63.10(a) of this part. On or after April 4, 2024 or once the report template for this subpart has been available on the CEDRI website for six months, whichever date is later, owners or operators must submit subsequent Periodic Reports in accordance with § 63.10(a) of this part except for the items in paragraph (iv) of this section. The items in paragraph (iv) of this section must be submitted using the appropriate electronic report template on the CEDRI website for this subpart and following the procedures specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Refinery Sector lead. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

* * * * *

(iv) For each pressure release to the atmosphere during the reporting period from a pressure relief device in organic HAP service subject to § 63.648(j)(3), report the following information:

(A) Pressure relief device identification name or number.

(B) The start time and date of the pressure release.

(C) The duration of the pressure release (in hours).

(D) An estimate of the mass quantity of each organic HAP released (in pounds).

(E) 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. Owners or operators must submit the Periodic Report in accordance with § 63.10(a) of this part. On or after April 4, 2024 or once the report template for this subpart has been available on the CEDRI website for six months, whichever date is later, owners or operators must submit subsequent Periodic Reports in accordance with § 63.10(a) of this part except for the items in paragraph (iv) of this section. The items in paragraph (iv) of this section must be submitted using the appropriate electronic report template on the CEDRI website and following the procedures specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Refinery Sector lead. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

* * * * *

(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 type of deviation (*e.g.,* flare tip velocity, valve position for pressure-assisted flares, combustion zone net heating value, or net heating value dilution parameter) and the flare tip velocity, if applicable, and the net heating value operating parameter(s) determined following the methods in § 63.670(k) through (n) as applicable.

(iv) An indication whether there were any flaring events meeting the criteria in § 63.670(o)(3) that occurred during the reporting period. If there were flaring events meeting the criteria in § 63.670(o)(3), report the following information for each such flaring event:

(A) Flare identification name or number.

(B) The type of flaring event.

(C) The start and stop time and date of the flaring event.

(D) The length of time (in minutes) for which emissions were visible from the flare during the event.

(E) 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.

(F) 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.

* * * * *

(13) * * *

(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 concentration of the vapors was 10 percent or greater of its LEL, also include the concentration of the vapors at the time active purging was initiated.

* * * * *

(i) * * *

(9) * * *

(vi) On and after April 4, 2024, for pressure-assisted flares, retain records of pressure and valve positions as required in § 63.670(d)(3) for a minimum of 2 years, records of when valve position was not correct for measured pressure for 5 years, and records of a cross-light performance demonstration as specified in § 63.670(b)(2) for 5 years.

* * * * *

(11) * * *

(ii) Records of the number of releases during each calendar year and, prior to June 3, 2024, 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.

* * * * *

(12) * * *

(ii) If complying with the requirements of § 63.643(c)(1)(i) and the concentration of the vapor at the time of the vessel opening exceeds 10 percent of its LEL, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and the concentration of the vapor 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 concentration of the vapor at the time of the active purging was initiated exceeds 10 percent of its LEL, 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 concentration of the vapors in the equipment when active purging was initiated.

* * * * *

(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 concentration of the vapors in the equipment at the time of discharge to the atmosphere for each applicable maintenance vent opening.

(vi) If complying with the requirements of § 63.643(c)(1)(v), identification of the maintenance vent, the process units or equipment associated with the maintenance vent, records documenting actions taken to comply with other applicable alternatives and why utilization of this alternative was required, the date of maintenance vent opening, the equipment pressure and concentration of the vapors in the equipment at the time of discharge, an indication of whether active purging was performed and the pressure of the equipment during the installation or removal of the blind if active purging was used, the duration the maintenance vent was open during the blind installation or removal process, 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.

■ 6. Amend § 63.670 by:

■ a. Revising paragraphs (b) and (d) introductory text;

■ b. Adding paragraph (d)(3);

■ c. Revising paragraphs (e), (l)(5) introductory text, (o)(4)(iv), (o)(6), and (o)(7)(ii) through (o)(7)(v).

The addition and revisions read as follows:

§ 63.670 Requirements for flare control devices.

* * * * *

(b) *Pilot flame presence.* The owner or operator shall operate each flare with a pilot flame present on an individual burner or stage of burners 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 on an individual burner or stage of burners 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 on an individual burner or stage of burners as specified in paragraph (g) of this section. Beginning on April 4, 2024, pressure-assisted flares using stages of burners that cross-light must also comply with paragraphs (b)(1) and (2) of this section.

(1) Each stage of burners that cross-lights in the pressure-assisted flare must have at least two pilots with at least one continuously lit and capable of igniting all regulated material that is routed to that stage of burners.

(2) Unless the owner or operator of a pressure-assisted flare chooses to conduct a cross-light performance demonstration as specified in this paragraph, the owner or operator must ensure that if a stage of burners on the flare uses cross-lighting, that the distance between any two burners in series on that stage is no more than 6 feet when measured from the center of one burner to the next burner. A distance greater than 6 feet between any two burners in series may be used provided the owner or operator complies with the requirements in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must conduct a performance demonstration that confirms the pressure-assisted flare will cross-light a minimum of three burners and the spacing between the burners and location of the pilot flame must be representative of the projected installation.

(ii) The compliance demonstration must be approved by the permitting authority and a copy of this approval must be maintained onsite.

(iii) The compliance demonstration report must include the information in paragraphs (b)(2)(iii)(A) through (K) of this section.

(A) A protocol describing the test methodology used, associated test method QA/QC parameters.

(B) The waste gas composition and NHVcz of the gas tested.

(C) The velocity of the waste gas tested.

(D) The pressure-assisted multi-point flare burner tip pressure.

(E) The time, length, and duration of the test.

(F) Records of whether a successful cross-light was observed over all of the burners and the length of time it took for the burners to cross-light.

(G) Records of maintaining a stable flame after a successful cross-light and the duration for which this was observed.

(H) Records of any smoking events during the cross-light.

(I) Waste gas temperature.

(J) Meteorological conditions (*e.g.,* ambient temperature, barometric pressure, wind speed and direction, and relative humidity) during the demonstration.

(K) An indication whether there were any observed flare flameouts and if so, the number and duration of each flare flameout.

* * * * *

(d) *Flare tip velocity.* Except as provided in paragraph (d)(3) of this section for pressure-assisted flares, 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.

* * * * *

(3) Pressure-assisted flares are not subject to the flare tip velocity limits in either paragraph (d)(1) or (2) of this section. In lieu of the flare tip velocity limits, beginning on April 4, 2024, the owner or operator of a pressure-assisted flare must install and operate pressure monitor(s) on the main flare header, as well as a valve position indicator monitoring system for each staging valve to ensure that the flare operates within the proper range of conditions as specified by the manufacturer. The pressure monitor must meet the requirements in Table 13 of this subpart.

(e) *Combustion zone operating limits.* The owner or operator shall operate the flare to maintain the net heating value of flare combustion zone gas (NHV_{cz}) at or above the applicable limits in paragraphs (e)(1) and (2) of this section 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.

(1) For all flares other than pressure-assisted flares, 270 British thermal units per standard cubic feet (Btu/scf).

(2) Beginning on April 4, 2024, for each pressure-assisted flare, 800 Btu/scf.

* * * * *

(l) * * *

(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 of a flare other than a pressure-assisted flare 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 non-pressure-assisted flares at the petroleum refinery and comply using the calculation methods (l)(5)(ii) of this section for other flares. However, for each non-pressure-assisted 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. For pressure-assisted flares, beginning on April 4, 2024, the owner or operator must use the calculation method in paragraph (l)(5)(ii) of this section.

* * * * *

(o) * * *

(4) * * *

(iv) Prior to June 3, 2024, 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.

* * * * *

(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. Prior to June 3, 2024, 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) * * *

(ii) Prior to June 3, 2024, 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. On and after June 3, 2024, two visible emissions exceedance events meeting the criteria in paragraph (o)(3)(i) of this section from a single flare in a 3 calendar year period for the same root cause for the same equipment.

(iii) Prior to June 3, 2024, 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. On and after June 3, 2024, two flare tip velocity exceedance events meeting the criteria in paragraph (o)(3)(ii) of this section from a single flare in a 3 calendar year period for the same root cause for the same equipment.

(iv) Prior to June 3, 2024, 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. On and after June 3, 2024, three visible emissions exceedance events meeting the criteria in paragraph (o)(3)(i) of this section from a single flare in a 3 calendar year period for any reason.

(v) Prior to June 3, 2024, 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. On and after June 3, 2024, three flare tip velocity exceedance events meeting the criteria in paragraph (o)(3)(ii) of this section from a single flare in a 3 calendar year period for any reason.

* * * * *

■ 7. Amend § 63.671 by:

■ a. Revising paragraph (e) introductory text; and

■ b. Adding paragraphs (e)(4) and (f).

The additions and revision read as follows:

§ 63.671 Requirements for flare monitoring systems.

* * * * *

(e) *Additional requirements for gas chromatographs.* For monitors used to determine compositional analysis for net heating value per § 63.670(j)(1) that include a gas chromatograph, the gas chromatograph must also meet the requirements of paragraphs (e)(1) through (4) of this section.

* * * * *

(4) Beginning on April 4, 2024, the owner or operator must initially determine the average instrument calibration error during the Seven (7)-Day Calibration Error Test Period and subsequently perform daily calibration and quarterly audits using either the compound-specific calibration error (CE) method provided in paragraph (i) of this section or using the net heating value (NHV) method provided in paragraph (ii) of this section.

(i) The average instrument CE for each calibration compound at any calibration concentration must not differ by more than 10 percent from the certified cylinder gas value. The CE for each component in the calibration blend must be calculated using the following equation:

Where:

$$CE = \frac{C_m - C_a}{C_a} \times 100$$

Where:

C_m = Average instrument response (ppm).

C_a = Certified cylinder gas value (ppm).

(ii) The CE for NHV at any calibration level must not differ by more than 10 percent from the certified cylinder gas value. The CE for must be calculated using the following equation:

$$CE = \frac{NHV_{measured} - NHV_a}{NHV_a} \times 100$$

Where:

$NHV_{measured}$ = Average instrument response (Btu/scf). NHV calculations must be based on the individual component properties in table 12 of this subpart.

NHV_a = Certified cylinder gas value (Btu/scf).

(f) *Additional requirements for continuous process mass spectrometers.* Beginning on April 4, 2024, for continuous process mass spectrometers used to determine compositional analysis for net heating value per § 63.670(j)(1) without the use of gas chromatography, the continuous process mass spectrometer must also meet the requirements of paragraphs (f)(1) through (7) of this section.

(1) You must meet the calibration gas requirements in paragraph (e)(2) of this section. You may augment the minimum list of calibration gas components found in paragraph (e)(2) of this section with compounds found during a pre-survey or known to be in the gas through process knowledge.

(2) Calibration gas cylinders (*i.e.,* low-, mid-, and high-levels) must be certified to an accuracy of 2 percent and traceable to National Institute of Standards and Technology (NIST) standards.

(3) For unknown gas components that have similar analytical mass fragments to calibration compounds, you may report the unknowns as an increase in the overlapped calibration gas compound. For unknown compounds that produce mass fragments that do not overlap calibration compounds, you may use the response factor for the nearest molecular weight hydrocarbon in the calibration mix to quantify the unknown component's net heating value of flare vent gas (NHV_{vg}).

(4) You may use the response factor for n-pentane to quantify any unknown components detected with a higher molecular weight than n-pentane.

(5) You must perform an initial calibration to identify mass fragment overlap and response factors for the target compounds.

(6) You must meet applicable requirements in Table 13 of this subpart for Net Heating Value by Mass Spectrometer.

(7) The owner or operator must estimate the instrument calibration error in accordance with paragraph (e)(4) of this section.

■ 8. Amend appendix to subpart CC of part 63 by revising table 13 to read as follows:

Appendix to Subpart CC of Part 63—Tables

* * * * *

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).	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 of flow rate at velocities greater than 0.3 meters per second (1 feet per second).	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.

TABLE 13—CALIBRATION AND QUALITY CONTROL REQUIREMENTS FOR CPMS—Continued

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).
Net Heating Value by Mass Spectrometer.	As specified in Performance Specifications 9 of 40 CFR part 60, appendix B.	Follow the procedure in Performance Specification 9 of 40 CFR part 60, appendix B, including performing an initial multi-point calibration check at three concentrations following the procedure in section 10.1 of Performance Specification 9, except that 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. Where feasible, 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.

Subpart YY—National Emission Standards for Hazardous Air Pollutants Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards

■ 9. Amend § 63.1100 by revising paragraphs (b) and (g)(7)(iii) to read as follows:

§ 63.1100 Applicability.

* * * * *

(b) *Subpart A requirements.* The following provisions of subpart A of this part (General Provisions), §§ 63.1 through 63.5, and §§ 63.12 through 63.15, apply to owners or operators of affected sources subject to this subpart. For sources that reclassify from major source to area source status, the applicable provisions of § 63.9(j) and (k) apply. Beginning no later than the compliance dates specified in § 63.1102(c), for ethylene production affected sources, §§ 63.7(a)(4), (c), (e)(4), and (g)(2), § 63.9(k), and 63.10(b)(2)(vi) also apply.

* * * * *

(g) * * *

(7) * * *

(iii) Beginning no later than the compliance dates specified in § 63.1102(c), flares subject to the requirements in 40 CFR part 63, subpart CC and used as a control device for an emission point subject to the requirements in Table 7 to § 63.1103(e) are only required to comply with the flare requirements in 40 CFR part 63, subpart CC.

■ 10. Amend § 63.1102 by revising paragraphs (c)(11), (d)(2)(ii), and (e)(2)(iii) to read as follows:

§ 63.1102 Compliance schedule.

* * * * *

(c) * * *

(11) The requirements in § 63.1108(a)(4), (b)(1)(ii), (b)(2), and (b)(4)(ii)(B).

* * * * *

(d) * * *

(2) * * *

(ii) The compliance requirements specified in § 63.1108(a)(4), (b)(1)(ii), (b)(2), and (b)(4)(ii)(B).

* * * * *

(e) * * *

(2) * * *

(iii) The compliance requirements specified in § 63.1108(a)(4), (b)(1)(ii), (b)(2), and (b)(4)(ii)(B).

* * * * *

■ 11. Amend § 63.1103 by:

■ a. Revising paragraphs (e)(4)(iii), (e)(4)(vii)(B), (e)(5)(i)(A), (e)(5)(i)(B), (e)(5)(ii), and (e)(7)(i);

■ b. Removing paragraphs (e)(7)(i)(A) and (e)(7)(i)(B);

■ c. Revising paragraphs (e)(8)(i) and (e)(10) introductory text; and

■ d. Adding paragraph (e)(10)(iv).

The addition and revisions read as follows:

§ 63.1103 Source category-specific applicability, definitions, and requirements.

* * * * *

(e) * * *

(4) * * *

(iii) Instead of complying with § 63.670(o)(2)(iii) of subpart CC, if required to develop a flare management plan and submit it to the Administrator, then the owner or operator must also submit all versions of the plan in portable document format (PDF) to the EPA following the procedure specified in § 63.9(k), except any medium submitted through U.S. mail must be sent to the attention of the Ethylene Production Sector Lead.

* * * * *

(vii) * * *

(B) The owner or operator must comply with the NHVcz requirements in § 63.670(e)(2) of subpart CC;

* * * * *

(5) * * *

(i) * * *

(A) The concentration of the vapor in the equipment served by the maintenance vent is less than 10 percent of its lower explosive limit (LEL).

(B) If there is no ability to measure the concentration 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 pounds per square inch gauge (psig) or less. Upon opening the maintenance vent, active purging of the equipment cannot be used until the concentration of the vapors in the maintenance vent (or inside the equipment if the maintenance is a hatch or similar type of opening) is less than 10 percent of its LEL.

* * * * *

(ii) Except for maintenance vents complying with the alternative in paragraph (e)(5)(i)(C) of this section, the owner or operator must determine the concentration of the vapor or, if applicable, equipment pressure using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications.

* * * * *

(7) * * *

(i) During normal operations, conduct daily inspections of the firebox burners and repair all burners that are impinging on the radiant tube(s) as soon as practical, but not later than 1 calendar day after the flame impingement is found. The owner or operator may delay burner repair beyond 1 calendar day provided the repair cannot be completed during normal operations, the burner cannot be shutdown without significantly impacting the furnace heat distribution and firing rate, and action is taken to reduce flame impingement as much as possible during continued operation. If a delay of repair is required to fully resolve burner flame impingement, repair must be completed following the next planned decoking operation (and before returning the ethylene cracking furnace back to normal operations) or during the next ethylene cracking furnace complete shutdown (when the ethylene cracking furnace firebox is taken completely offline), whichever is earlier. An inspection may include, but is not limited to: visual inspection of the radiant tube(s) for localized bright spots (this may be confirmed with a temperature gun), use of luminescent powders injected into the burner to illuminate the flame pattern, or identifying continued localized coke buildup that causes short runtimes between decoking cycles. A repair may include, but is not limited to: Taking the burner out of service, replacing the burner, adjusting the alignment of the burner, adjusting burner configuration, making burner air corrections, repairing a malfunction of the fuel liquid removal equipment, or adding insulation around the radiant tube(s).

* * * * *

(8) * * *

(i) Prior to decoking operation, inspect the applicable ethylene cracking furnace isolation valve(s) to confirm that the radiant tube(s) being decoked is completely isolated from the ethylene production process so that no emissions generated from decoking operations are sent to the ethylene production process. If poor isolation is identified, then the owner or operator must rectify the isolation issue prior to continuing decoking operations to prevent leaks into the ethylene production process, unless the owner or operator determines that damage to the radiant tube(s) or ethylene cracking furnace could occur if the repair was attempted prior to completing a decoking operation and/or prior to the ethylene cracking furnace being shut down.

* * * * *

(10) *Storage vessel degassing.* Beginning no later than the compliance dates specified in § 63.1102(c), for each storage vessel subject to paragraph (b) or (c) of Table 7 to § 63.1103(e), the owner or operator must comply with

paragraphs (e)(10)(i) through (iv) of this section during storage vessel shutdown operations (*i.e.,* emptying and degassing of a storage vessel) until the vapor space concentration in the storage vessel is less than 10 percent of the LEL. The owner or operator must determine the concentration using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications.

* * * * *

(iv) For floating roof storage vessels, the storage vessel may be opened to set up equipment (*e.g.,* making connections to a temporary control device) for the shutdown operations but must not be actively degassed during this time period.

* * * * *

■ 12. Amend § 63.1107 by revising paragraphs (h)(3)(iv), (h)(3)(v)(B) and (C), (h)(6) introductory text, and (h)(6)(ii) to read as follows:

§ 63.1107 Equipment leaks.

* * * * *

(h) * * *

(3) * * *

(iv) The owner or operator must determine the total number of release events that occurred during the calendar year for each affected pressure relief device separately. Prior to June 3, 2024, the owner or operator must 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 § 63.1103(e)(2).

(v) * * *

(B) Prior to June 3, 2024, 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. On and after June 3, 2024, a second release event from a single pressure relief device in a 3-calendar year period for the same root cause for the same equipment.

(C) Prior to June 3, 2024, a third release event not including force majeure events from a single pressure relief device in a 3-calendar year period for any reason. On and after June 3, 2024, a third release event from a single pressure relief device in a 3-calendar year period for any reason.

* * * * *

(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 (h)(6)(i) through (iii) of this section.

* * * * *

(ii) Prior to June 3, 2024, 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 § 63.1103(e)(2).

* * * * *

■ 13. Amend § 63.1109 by revising paragraphs (f)(2), (3), and (5), and (i)(2) to read as follows:

§ 63.1109 Recordkeeping requirements.

* * * * *

(f) * * *

(2) If complying with the requirements of § 63.1103(e)(5)(i)(A) and the concentration of the vapor at the time of the vessel opening exceeds 10 percent of its LEL, records that identify the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and the concentration of the vapor at the time of the vessel opening.

(3) If complying with the requirements of § 63.1103(e)(5)(i)(B) and either the vessel pressure at the time of the vessel opening exceeds 5 psig or the concentration of the vapor at the time of the active purging was initiated exceeds 10 percent of its LEL, records that identify 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 concentration of the vapors in the equipment when active purging was initiated.

* * * * *

(5) If complying with the requirements of § 63.1103(e)(5)(i)(D), identification of the maintenance vent, the process units or equipment associated with the maintenance vent, records documenting actions taken to comply with other applicable alternatives and why utilization of this alternative was required, the date of maintenance vent opening, the equipment pressure and concentration of the vapors in the equipment at the time of discharge, an indication of whether active purging was performed and the pressure of the equipment during the installation or removal of the blind if active purging was used, the duration the maintenance vent was open during the blind installation or removal process, 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.

* * * * *

(i) * * *

(2) Records of the number of releases during each calendar year and, prior to June 3, 2024, 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.

* * * * *

■ 14. Amend § 63.1110 by revising paragraphs (a)(10), (e)(4)(iii), (e)(4)(iv)(A) and (B), (e)(5)(iii), and (e)(8)(iii) to read as follows:

§ 63.1110 Reporting requirements.

(a) * * *

(10)(i) Beginning no later than the compliance dates specified in § 63.1102(c) for ethylene production affected sources, specified in § 63.1102(d) for cyanide chemicals manufacturing affected sources, and specified in § 63.1102(e) for carbon black production affected sources, within 60 days after the date of completing each performance test required by this subpart or applicability assessment required by § 63.1103(f)(3)(iv), the owner or operator must submit the results of the performance test or applicability assessment following the procedures specified in § 63.9(k). Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

(ii) Beginning no later than the compliance dates specified in § 63.1102(c) through (e), the owner or operator must submit all subsequent Notification of Compliance Status reports required under paragraph (a)(4) of this section in portable document format (PDF) format to the EPA following the procedure specified in § 63.9(k). All subsequent Periodic Reports required under paragraph (a)(5) of this section must be submitted to the EPA via CEDRI using the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart and following the procedure specified in § 63.9(k) beginning no later than the compliance dates specified in § 63.1102(c) through (e) or once the report template has been available on the CEDRI website for 1 year, whichever date is later. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports under § 63.9(i) and § 63.10(a) of subpart A, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. Any medium submitted through mail under § 63.9(k) for a Notification of Compliance Status report or Periodic Report must be sent to the attention of the Ethylene Production Sector Lead, Cyanide Chemicals Manufacturing Sector Lead, or Carbon Black Production Sector Lead, as appropriate.

(iii) Beginning no later than the compliance date specified in § 63.1102(c) or once the report template for this subpart has been available on the CEDRI website for six months, whichever date is later, the items in § 63.1110(e)(4)(iv) and § 63.1110(e)(8)(iii) must be submitted to the EPA via CEDRI as specified in § 63.9(k) using the appropriate electronic report template on the CEDRI website for reporting that information. The report submitted to CEDRI must also contain company identifier information (including the company name and address) and the beginning and ending dates of the time period covered by the report. Once you begin submitting Periodic Reports to CEDRI in accordance with paragraph (a)(10)(ii) of this section, the items in § 63.1110(e)(4)(iv) and § 63.1110(e)(8)(iii) must be included in those Periodic Reports instead of submitting the information using the separate template.

* * * * *

(e) * * *

(4) * * *

(iii) The periods specified in § 63.1109(e)(6). Indicate the date and start time for the period, and the net heating value operating parameter(s) determined following the methods in § 63.670(k) through (n) of subpart CC as applicable.

(iv) * * *

(A) Flare identification name or number and the start and stop time and date of the flaring event.

(B) The length of time (in minutes) that emissions were visible from the flare during the event.

* * * * *

(5) * * *

(iii) The LEL, 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 § 63.1103(e)(5)(i)(B) was used and active purging was initiated while the concentration of the vapor was 10 percent or greater of its LEL, also include the concentration of the vapors at the time active purging was initiated.

* * * * *

(8) * * *

(iii) For pressure relief devices in organic HAP service subject to § 63.1107(h)(3), report each pressure release to the atmosphere, including pressure relief device identification name or number; start date and start time and duration (in hours) of the pressure release; an estimate (in pounds) of the mass quantity of each organic HAP released; 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.

* * * * *

Subpart EEEE—National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)

■ 15. Amend § 63.2346 by:

■ a. Revising paragraph (a)(6) introductory text;

■ b. Adding paragraph (a)(6)(iv); and

■ c. Revising paragraph (e).

The addition and revisions read as follows:

§ 63.2346 What emission limitations, operating limits, and work practice standards must I meet?

(a) * * *

(6) Beginning no later than the compliance dates specified in § 63.2342(e), tank emissions during storage tank shutdown operations (*i.e.,* emptying and degassing of a storage tank) for each storage tank at an affected source storing organic liquids that meets the tank capacity and liquid vapor pressure criteria for control in items 2 through 6 of Table 2 to this subpart, or items 1 through 3 of Table 2b to this subpart, you must comply with paragraphs (a)(6)(i) through (iv) of this section during tank emptying and degassing until the vapor space concentration in the tank is less than 10 percent of the lower explosive limit (LEL). The owner or operator must determine the concentration using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications.

* * * * *

(iv) For floating roof storage tanks, the storage tank may be opened to set up equipment (*e.g.,* making connections to a temporary control device) for the shutdown operations but must not be actively degassed during this time period.

* * * * *

(e) *Operating limits.* For each high throughput transfer rack, you must meet each operating limit in Table 3 to this subpart for each control device used to comply with the provisions of this subpart whenever emissions from the loading of organic liquids are routed to the control device. Except as specified in paragraph (k) of this section, for each storage tank and low throughput transfer rack, you must comply with paragraph (l) of this section and the requirements for monitored parameters as specified in subpart SS of this part, for storage tanks and, during the loading of organic liquids, for low throughput transfer racks, respectively. Alternatively, you may comply with the operating limits in table 3 to this subpart.

* * * * *

■ 16. Amend § 63.2378 by revising and republishing paragraph (e) to read as follows:

§ 63.2378 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

* * * * *

(e) Beginning no later than the compliance dates specified in § 63.2342(e), paragraphs (b) through (d) of this section no longer apply. Instead, you must be in compliance with each emission limitation, operating limit, and work practice standard specified in paragraph (a) of this section at all times, except during periods of nonoperation of the affected source (or specific portion thereof) resulting in cessation of the emissions to which this subpart applies and must comply with the requirements specified in paragraphs (e)(1) through (4) of this section, as applicable. Equipment subject to the work practice standards for equipment leak components in Table 4 to this subpart, item 4 are not subject to this paragraph (e).

(1) Except as specified in paragraphs (e)(3) and (4) of this section, the use of a bypass line at any time on a closed vent system to divert a vent stream to the atmosphere or to a control device not meeting the requirements specified in paragraph (a) of this section is an emissions standards deviation.

(2) If you are subject to the bypass monitoring requirements of § 63.983(a)(3), then you must continue to comply with the requirements in § 63.983(a)(3) and the recordkeeping and reporting requirements in §§ 63.998(d)(1)(ii) and 63.999(c)(2), in addition to § 63.2346(l), the recordkeeping requirements specified in § 63.2390(g), and the reporting requirements specified in § 63.2386(c)(12).

(3) Periods of planned routine maintenance of a control device used to control storage tank breathing loss emissions, during which the control device does not meet the emission limits in Table 2 or 2b to this subpart, must not exceed 240 hours per year. The level of material in the storage tank shall not be increased during periods that the closed-vent system or control device is bypassed to perform planned routine maintenance.

(4) If you elect to route emissions from storage tanks to a fuel gas system or to a process, as allowed by § 63.982(d), to comply with the emission limits in Table 2 or 2b to this subpart, the total aggregate amount of time during which the breathing loss emissions bypass the fuel gas system or process during the calendar year without being routed to a control device, for all reasons (except product changeovers of flexible operation units and periods when a storage tank has been emptied and degassed), must not exceed 240 hours. The level of material in the storage tank shall not be increased during periods that the fuel gas system or process is bypassed.

* * * * *

■ 17. Amend § 63.2382 by revising paragraph (d)(3) to read as follows:

§ 63.2382 What notifications must I submit and when and what information should be submitted?

* * * * *

(d) * * *

(3) *Submitting Notification of Compliance Status.* Beginning no later than the compliance dates specified in § 63.2342(e), you must submit all subsequent Notification of Compliance Status reports in portable document format (PDF) format to the EPA following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Organic Liquids Distribution Sector Lead.

■ 18. Amend § 63.2386 by:

■ a. Revising paragraphs (f), (g), and (h); and

■ b. Removing paragraphs (i) and (j).

The revisions read as follows:

§ 63.2386 What reports must I submit and when and what information is to be submitted in each?

* * * * *

(f) Beginning no later than the compliance dates specified in § 63.2342(e), you must submit all Compliance reports to the EPA following the procedure specified in § 63.9(k), except any medium submitted through U.S. mail must be sent to the attention of the Organic Liquids Distribution Sector Lead. You must use the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports under §§ 63.9(i) and 63.10(a), the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(g) Beginning no later than the compliance dates specified in § 63.2342(e), you must start submitting performance test reports in accordance with this paragraph. Unless otherwise specified in this subpart, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test following the procedures specified in § 63.9(k). Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

(h) Beginning no later than the compliance dates specified in § 63.2342(e), you must start submitting performance evaluation reports in accordance with this paragraph. Unless otherwise specified in this subpart, within 60 days after the date of completing each CEMS performance evaluation (as defined in § 63.2) that includes a relative accuracy test audit (RATA), you must submit the results of the performance evaluation following the procedures specified in § 63.9(k). The results of performance evaluations of CEMS measuring RATA pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website. The results of performance evaluations of CEMS measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be included as an attachment in the ERT or alternate electronic file.

§ 63.2406 [Amended]

■ 19. Amend § 63.2406 by removing the definition of ''Force majeure event''.

■ 20. Amend table 12 to subpart EEEE of part 63 by:

■ a. Adding the entry ''63.7(a)(4)'' in numerical order; and

■ b. Revising the entry ''63.9(k)''.

The addition and revision read as follows:

Table 12 to Subpart EEEE of Part 63—Applicability of General Provisions to Subpart EEEE

* * * * *

Citation	Subject	Brief description	Applies to subpart EEEE
* * *	* * *	* * *	*
§ 63.7(a)(4)	Force Majeure—Performance Testing Delay	Requirements to claim a delay in conducting a performance test due to force majeure.	Yes.
* * *	* * *	* * *	*
§ 63.9(k)	Electronic reporting procedures	Procedure to report electronically for notifications and reports.	Yes.
* * *	* * *	* * *	*

Subpart FFFF—National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing

■ 21. Amend § 63.2450 by revising paragraphs (e)(1), (e)(5)(iv), (e)(5)(viii)(B), (e)(6)(i), (e)(7) introductory text, (v)(1)(i), (v)(1)(ii), and (v)(2) to read as follows:

§ 63.2450 What are my general requirements for complying with this subpart?

* * * * *

(e) * * *

(1) Except when complying with § 63.2485 or paragraph (e)(7) of this section, if you reduce organic HAP emissions by venting emissions through a closed-vent system to any combination of control devices (except a flare) or recovery devices, you must meet the requirements of paragraph (e)(4) of this section, and the requirements of § 63.982(c) and the requirements referenced therein.

* * * * *

(5) * * *

(iv) Instead of complying with paragraph (o)(2)(iii) of § 63.670 of subpart CC, if required to develop a flare management plan and submit it to the Administrator, then you must also submit all versions of the plan in portable document format (PDF) to the EPA following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Miscellaneous Organic Chemical Manufacturing Sector Lead.

* * * * *

(viii) * * *

(B) You must comply with the NHVcz requirements in paragraph (e)(2) of § 63.670 of subpart CC;

* * * * *

(6) * * *

(i) If you are subject to the bypass monitoring requirements of § 63.148(f) of subpart G, then you must continue to comply with the requirements in § 63.148(f) of subpart G and the recordkeeping and reporting requirements in §§ 63.148(j)(2) and (3) of subpart G, and § 63.148(i)(3) of subpart G, in addition to the applicable requirements specified in § 63.2485(q), the recordkeeping requirements specified in § 63.2525(n), and the reporting requirements specified in § 63.2520(e)(12).

* * * * *

(7) Beginning no later than the compliance dates specified in § 63.2445(g), if you reduce organic HAP emissions by venting emissions through a closed-vent system to an adsorber(s) that cannot be regenerated or a regenerative adsorber(s) that is regenerated offsite, then you must comply with paragraphs (e)(4) and (6) of this section, § 63.2470(c)(3), §§ 63.2520(d)(6) and (e)(13), § 63.2525(o), the requirements in § 63.983 including the requirements referenced therein, and you must install a system of two or more adsorber units in series and comply with the requirements specified in paragraphs (e)(7)(i) through (iii) of this section.

* * * * *

(v) * * *

(1) * * *

(i) The vapor in the equipment served by the maintenance vent has a concentration less than 10 percent of its lower explosive limit (LEL) and has an outlet concentration less than or equal to 20 ppmv hydrogen halide and halogen HAP.

(ii) If there is no ability to measure the concentration 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 pounds per square inch gauge (psig) or less. Upon opening the maintenance vent, active purging of the equipment cannot be used until the concentration of the vapors in the maintenance vent (or inside the equipment if the maintenance is a hatch or similar type of opening) is less than 10 percent of its LEL.

* * * * *

(2) Except for maintenance vents complying with the alternative in paragraph (v)(1)(iii) of this section, you must determine the concentration of the vapor or, if applicable, equipment pressure using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications.

* * * * *

■ 22. Amend § 63.2460 by revising paragraph (c)(9) introductory text to read as follows:

§ 63.2460 What requirements must I meet for batch process vents?

* * * * *

(c) * * *

(9) *Requirements for a biofilter.* If you use a biofilter to meet either the 95-percent reduction requirement or outlet concentration requirement specified in Table 2 to this subpart, you must meet the requirements specified in paragraphs (c)(9)(i) through (iv) of this section.

* * * * *

■ 23. Amend § 63.2470 by revising paragraph (f) introductory text and adding paragraph (f)(4) to read as follows:

§ 63.2470 What requirements must I meet for storage tanks?

* * * * *

(f) *Storage tank degassing.* Beginning no later than the compliance dates specified in § 63.2445(g), for each storage tank subject to item 1 of Table 4 to this subpart, you must comply with paragraphs (f)(1) through (4) of this section during storage tank shutdown operations (*i.e.,* emptying and degassing of a storage tank) until the vapor space concentration in the storage tank is less than 10 percent of the LEL. You must determine the concentration using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications.

* * * * *

(4) For floating roof storage tanks, the storage tank may be opened to set up equipment (*e.g.,* making connections to a temporary control device) for the shutdown operations but must not be actively degassed during this time period.

■ 24. Amend § 63.2480 by revising paragraphs (a), (e)(2)(ii), (e)(2)(iii), (e)(3)(iv), (e)(3)(v)(B), (e)(3)(v)(C), (e)(6)(ii), (f)(18)(iii), (f)(18)(vi), (f)(18)(x), and (f)(18)(xiii) to read as follows:

§ 63.2480 What requirements must I meet for equipment leaks?

(a) You must meet each requirement in table 6 to this subpart that applies to your equipment leaks, except as specified in paragraphs (b) through (f) of this section. For each light liquid pump, pressure relief device, and connector in ethylene oxide service as defined in § 63.2550(i), you must also meet the applicable requirements specified in §§ 63.2492 and 63.2493(d) and (e).

* * * * *

(e) * * *

(2) * * *

(ii) If the pressure relief device includes a rupture disk, either comply with the requirements in paragraph (e)(2)(i) of this section (and do not replace 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.

(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. You must not initiate startup of the equipment served by the rupture disk until the rupture disc is replaced.

(3) * * *

(iv) You must determine the total number of release events that occurred during the calendar year for each affected pressure relief device separately. Prior to June 3, 2024, you must 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 § 63.2550.

(v) * * *

(B) Prior to June 3, 2024, 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. On and after June 3, 2024, a second release event from a single pressure relief device in a 3 calendar year period for the same root cause for the same equipment.

(C) Prior to June 3, 2024, a third release event not including force majeure events from a single pressure relief device in a 3 calendar year period for any reason. On and after June 3, 2024, a third release event from a single pressure relief device in a 3 calendar year period for any reason.

* * * * *

(6) * * *

(ii) Prior to June 3, 2024, 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 § 63.2550.

* * * * *

(f) * * *

(18) * * *

(iii) In § 63.181(b)(3)(i), replace the reference to § 63.165(a) with § 63.2480(e)(1).

* * * * *

(vi) The information in § 63.165(a) required to be reported under § 63.182(d)(2)(xiv) is now required to be reported under § 63.2520(e)(15)(i) through (iii).

* * * * *

(x) The reference to § 63.1030(c) in § 63.1023(a)(1)(v) no longer applies. Instead comply with the § 63.2480(e)(1) and (2).

* * * * *

(xiii) The information in § 63.1030(b) required to be reported under § 63.1039(b)(4) is now required to be reported under § 63.2520(e)(15)(i) and (ii).

* * * * *

■ 25. Amend § 63.2490 by:

■ a. Revising paragraphs (a), (d) introductory text, and (d)(4)(iii) introductory text; and

■ b. Adding paragraph (e).

The addition and revisions read as follows:

§ 63.2490 What requirements must I meet for heat exchange systems?

(a) You must comply with each requirement in Table 10 to this subpart that applies to your heat exchange systems, except as specified in paragraphs (b) through (e) of this section.

* * * * *

(d) Unless one or more of the conditions specified in § 63.104(a)(1), (2), (5), and (6) or paragraph (e) of this section are met, beginning no later than the compliance dates specified in § 63.2445(g), the requirements of § 63.104 as specified in Table 10 to this subpart and paragraphs (b) and (c) of this section no longer apply. Instead, you must monitor the cooling water for the presence of total strippable hydrocarbons that indicate a leak according to paragraph (d)(1) of this section, and if you detect a leak, then you must repair it according to paragraphs (d)(2) and (3) of this section, unless repair is delayed according to paragraph (d)(4) of this section. At any time before the compliance dates specified in § 63.2445(g), you may choose to comply with the requirements in this paragraph (d) in lieu of the requirements of § 63.104 as specified in Table 10 to this subpart and paragraphs (b) and (c) of this section. The requirements in this paragraph (d) do not apply to heat exchange systems that have a maximum cooling water flow rate of 10 gallons per minute or less.

* * * * *

(4) * * *

(iii) The delay of repair action level is a total strippable hydrocarbon concentration (as methane) in the stripping gas of 62 ppmv or, for heat exchange systems with a recirculation rate of 10,000 gallons per minute or less, the delay of repair action level is a total hydrocarbon mass emissions rate (as methane) of 1.8 kg/hr. The delay of repair action level is assessed as described in paragraph (d)(4)(iii)(A) or (B) of this section, as applicable.

* * * * *

(e) If 99 percent by weight or more of the organic compounds that could leak into the heat exchange system are water soluble and have a Henry's Law Constant less than 5.0E–6 at 25 degrees Celsius (atmospheres-cubic meters/mol) and none of the conditions specified in § 63.104(a)(1), (2), (5), and (6) are met, beginning no later than the compliance dates specified in § 63.2445(g), you may monitor the cooling water for leaks according to the requirements in § 63.104(b) in lieu of using the Modified El Paso Method. If you detect a leak according to § 63.104(b), then you must repair it according to paragraph (e)(1) of this section, unless repair is delayed according to paragraph (e)(2) of this section.

(1) If a leak is detected using the methods described in paragraph (e) of this section, you must repair the leak as soon as practicable, but no later than 45 days after identifying the leak, except as specified in paragraph (e)(2) of this section. Repair must include re-monitoring at the monitoring location where the leak was identified to verify that the criteria in § 63.104(b)(6) is no longer met. Actions that can be taken to

achieve repair include but are not limited to:

(i) Physical modifications to the leaking heat exchanger, such as welding the leak or replacing a tube;

(ii) Blocking the leaking tube within the heat exchanger;

(iii) Changing the pressure so that water flows into the process fluid;

(iv) Replacing the heat exchanger or heat exchanger bundle; or

(v) Isolating, bypassing, or otherwise removing the leaking heat exchanger from service until it is otherwise repaired.

(2) You may delay repair when the conditions in § 63.104(e) are met.

■ 26. Amend § 63.2492 by revising paragraph (b) to read as follows:

§ 63.2492 How do I determine whether my process vent, storage tank, or equipment is in ethylene oxide service?

* * * * *

(b) For storage tanks, you must determine the concentration of ethylene oxide of the fluid stored in the storage tanks by complying with the requirements in paragraph (b)(1) or (2) of this section.

(1) You must measure the concentration of ethylene oxide of the fluid stored in the storage tanks using Method 624.1 of 40 CFR part 136, appendix A, or preparation by Method 5031 and analysis by Method 8260D (both incorporated by reference, see § 63.14) in the SW–846 Compendium. In lieu of preparation by SW–846 Method 5031, you may use SW–846 Method 5030B (incorporated by reference, see § 63.14), as long as: You do not use a preservative in the collected sample; you store the sample with minimal headspace as cold as possible and at least below 4 degrees C; and you analyze the sample as soon as possible, but in no case longer than 7 days from the time the sample was collected. If you are collecting a sample from a pressure vessel, you must maintain the sample under pressure both during and following sampling.

(2) Unless specified by the Administrator, you may calculate the concentration of ethylene oxide of the fluid stored in the storage tanks if information specific to the fluid stored is available. Information specific to the fluid stored includes concentration data from safety data sheets.

* * * * *

■ 27. Amend § 63.2493 by revising paragraphs (a)(2)(vi) introductory text, (a)(2)(vi)(C), (a)(2)(viii), (b)(2), (b)(4) introductory text, (b)(4)(iv), (b)(6), (d)(1)(iii), (d)(2)(iii), (d)(3), (d)(4)(v), and (e) introductory text to read as follows:

§ 63.2493 What requirements must I meet for process vents, storage tanks, or equipment that are in ethylene oxide service?

* * * * *

(a) * * *

(2) * * *

(vi) If you vent emissions through a closed-vent system to a scrubber with a reactant tank, then you must establish operating parameter limits by monitoring the operating parameters specified in paragraphs (a)(2)(vi)(A) through (C) of this section during the performance test.

* * * * *

(C) Temperature of the scrubber liquid entering the scrubber column. The temperature may be measured at any point after the heat exchanger and prior to entering the top of the scrubber column. Determine the average inlet scrubber liquid temperature as the average of the test run averages.

* * * * *

(viii) If you vent emissions through a closed-vent system to a control device other than a flare, scrubber with a reactant tank, or thermal oxidizer, then you must notify the Administrator of the operating parameters that you plan to monitor during the performance test prior to establishing operating parameter limits for the control device.

* * * * *

(b) * * *

(2) If you choose to reduce emissions of ethylene oxide by venting emissions through a closed-vent system to a non-flare control device that reduces ethylene oxide to less than 1 ppmv as specified in Table 1, 2, or 4 to this subpart, and you choose to comply with paragraph (a)(3)(i) of this section, then continuously monitor the ethylene oxide concentration at the exit of the control device using an FTIR CEMS meeting the requirements of Performance Specification 15 of 40 CFR part 60, appendix B, and § 63.2450(j). If you use an FTIR CEMS, you do not need to conduct the performance testing required in paragraph (b)(3) of this section or the operating parameter monitoring required in paragraphs (b)(4) through (6) of this section.

* * * * *

(4) If you vent emissions through a closed-vent system to a scrubber with a reactant tank, then you must comply with § 63.2450(e)(4) and (6) and the requirements in § 63.983, and you must meet the operating parameter limits specified in paragraphs (b)(4)(i) through (v) of this section.

* * * * *

(iv) Maximum temperature of the scrubber liquid entering the scrubber column, equal to the average temperature measured during the most recent performance test. Compliance with the inlet scrubber liquid temperature operating limit must be determined continuously on a 1-hour block basis. Use a temperature sensor with a minimum accuracy of ±1 percent over the normal range of the temperature measured, expressed in degrees Celsius, or 2.8 degrees Celsius, whichever is greater.

* * * * *

(6) If you vent emissions through a closed-vent system to a control device other than a flare, scrubber with a reactant tank, or thermal oxidizer, then you must comply with § 63.2450(e)(4) and (6) and the requirements in § 63.983, and you must monitor the operating parameters identified in paragraph (a)(2)(viii) of this section and meet the established operating parameter limits to ensure continuous compliance. The frequency of monitoring and averaging time will be determined based upon the information provided to the Administrator.

* * * * *

(d) * * *

(1) * * *

(iii) When a leak is detected, it must be repaired as soon as practicable, but not later than 15 calendar days after it is detected. Delay of repair of pumps for which leaks have been detected is allowed for pumps that are isolated from the process and that do not remain in ethylene oxide service.

(2) * * *

(iii) When a leak is detected, it must be repaired as soon as practicable, but not later than 15 calendar days after it is detected. Delay of repair of connectors for which leaks have been detected is allowed for connectors that are isolated from the process and that do not remain in ethylene oxide service.

(3) For each light liquid pump or connector in ethylene oxide service that is added to an MCPU, and for each light liquid pump or connector in ethylene oxide service that replaces a light liquid pump or connector in ethylene oxide service, you must initially monitor for leaks within 5 days after initial startup of the equipment.

(4) * * *

(v) Replace all references to § 63.2445(g) with § 63.2445(i).

(e) *Non-applicable referenced provisions.* The referenced provisions specified in paragraphs (e)(1) through (16) of this section do not apply when demonstrating compliance with this section.

* * * * *

■ 28. Amend § 63.2515 by revising paragraph (d) to read as follows:

§ 63.2515 What notifications must I submit and when?

* * * * *

(d) *Supplement to Notification of Compliance Status.* You must also submit supplements to the Notification of Compliance Status as specified in § 63.2520(d)(3) through (6).

■ 29. Amend § 63.2520 by:

■ a. Revising paragraph (d) introductory text;

■ b. Adding paragraph (d)(6);

■ c. Revising paragraphs (e) introductory text, (e)(2), (e)(14)(iii), (e)(16), (f) and (g); and

■ d. Removing paragraphs (h) and (i).

The addition and revisions read as follows:

§ 63.2520 What reports must I submit and when?

* * * * *

(d) *Notification of compliance status report.* You must submit a notification of compliance status report according to the schedule in paragraph (d)(1) of this section, and the notification of compliance status report must contain the information specified in paragraphs (d)(2) through (6) of this section.

* * * * *

(6) For adsorbers subject to the requirements of § 63.2450(e)(7), you must also submit the information listed in paragraphs (d)(6)(i) and (ii) of this section in a supplement to the Notification of Compliance Status within 150 days after the first applicable compliance date.

(i) Whether the adsorber cannot be regenerated or is a regenerative adsorber(s) that is regenerated off site.

(ii) The breakthrough limit and adsorber bed life established during the initial performance test or design evaluation of the adsorber.

(e) *Compliance report.* The compliance report must contain the information specified in paragraphs (e)(1) through (17) of this section. On and after August 12, 2023 or once the reporting template for this subpart has been available on the CEDRI website for 1 year, whichever date is later, you must submit all subsequent reports following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Miscellaneous Organic Chemical Manufacturing Sector Lead. You must use the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports under §§ 63.9(i) and 63.10(a) of subpart A, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

* * * * *

(2) Statement by a responsible official with that official's name, title, and signature, certifying the accuracy of the content of the report. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (e)(2).

* * * * *

(14) * * *

(iii) The lower explosive limit in percent, vessel pressure in psig, or mass in pounds of VOC in the equipment, as applicable, at the start of atmospheric venting. If the 5 psig vessel pressure option in § 63.2450(v)(1)(ii) was used and active purging was initiated while the concentration of the vapor was 10 percent or greater of its LEL, also include the concentration of the vapors at the time active purging was initiated.

* * * * *

(16) For each heat exchange system subject to § 63.2490(d) or (e), beginning no later than the compliance dates specified in § 63.2445(g), the reporting requirements of § 63.104(f)(2) no longer apply; instead, the compliance report must include the information specified in paragraphs (e)(16)(i) through (v) of this section.

(i) The number of heat exchange systems at the plant site subject to the monitoring requirements in § 63.2490(d) or (e) during the reporting period;

(ii) The number of heat exchange systems subject to the monitoring requirements in § 63.2490(d) or (e) at the plant site found to be leaking during the reporting period;

(iii) For each monitoring location where a leak was identified during the reporting period, identification of the monitoring location (*e.g.,* unique monitoring location or heat exchange system ID number), the measured total strippable hydrocarbon concentration or total hydrocarbon mass emissions rate (if complying with § 63.2490(d)) or the measured concentration of the monitored substance(s) (if complying with § 63.2490(e)), 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 or total hydrocarbon mass emissions rate (if complying with § 63.2490(d)) or the measured concentration of the monitored substance(s) (if complying with § 63.2490(e)) 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 or total hydrocarbon mass emissions rate (if complying with § 63.2490(d)) or the measured concentration of the monitored substance(s) (if complying with § 63.2490(e)) and date of each monitoring event conducted on the delayed repair during the reporting period, and an estimate in pounds of the potential total hydrocarbon emissions or monitored substance(s) emissions over the reporting period associated with the delayed repair.

* * * * *

(f) *Performance test reports.* Beginning no later than October 13, 2020, you must submit performance test reports in accordance with this paragraph (f). Unless otherwise specified in this subpart, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test following the procedures specified in § 63.9(k). Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

(g) *CEMS relative accuracy test audit (RATA) Performance evaluation reports.* Beginning no later than October 13, 2020, you must start submitting CEMS RATA performance evaluation reports in accordance with this paragraph (g).

Unless otherwise specified in this subpart, within 60 days after the date of completing each continuous monitoring system performance evaluation (as defined in § 63.2) that includes a RATA, you must submit the results of the performance evaluation following the procedures specified in § 63.9(k). The results of performance evaluations of CEMS measuring RATA pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website. The results of performance evaluations of CEMS measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be included as an attachment in the ERT or alternate electronic file.

■ 30. Amend § 63.2525 by:

■ a. Revising paragraphs (o), (p)(2), (p)(3), (p)(5), (q)(2), (r)(1), (r)(4)(iv) introductory text, (r)(4)(iv)(B) and (r)(4)(iv)(C); and

■ b. Adding paragraph (r)(4)(iv)(D).

The addition and revisions read as follows:

§ 63.2525 What records must I keep?

* * * * *

(o) For each nonregenerative adsorber and regenerative adsorber that is regenerated offsite subject to the requirements in § 63.2450(e)(7), you must keep the applicable records specified in paragraphs (o)(1) through (3) of this section.

(1) Breakthrough limit and bed life established according to § 63.2450(e)(7)(i).

(2) Each outlet HAP or TOC concentration measured according to §§ 63.2450(e)(7)(ii) and (e)(7)(iii).

(3) Date and time you last replaced the adsorbent.

(p) * * *

(2) If complying with the requirements of § 63.2450(v)(1)(i) and the concentration of the vapor at the time of the vessel opening exceeds 10 percent of its LEL, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and the concentration of the vapor at the time of the vessel opening.

(3) If complying with the requirements of § 63.2450(v)(1)(ii) and either the vessel pressure at the time of the vessel opening exceeds 5 psig or the concentration of the vapor at the time of the active purging was initiated exceeds 10 percent of its LEL, 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 concentration of the vapors in the equipment when active purging was initiated.

* * * * *

(5) If complying with the requirements of § 63.2450(v)(1)(iv), identification of the maintenance vent, the process units or equipment associated with the maintenance vent, records documenting actions taken to comply with other applicable alternatives and why utilization of this alternative was required, the date of maintenance vent opening, the equipment pressure and concentration of the vapors in the equipment at the time of discharge, an indication of whether active purging was performed and the pressure of the equipment during the installation or removal of the blind if active purging was used, the duration the maintenance vent was open during the blind installation or removal process, 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.

(q) * * *

(2) Records of the number of releases during each calendar year and, prior to June 3, 2024, 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 5 calendar years.

* * * * *

(r) * * *

(1) Monitoring data required by § 63.2490(d) and (e) that indicate a leak, the date the leak was detected, or, if applicable, the basis for determining there is no leak.

* * * * *

(4) * * *

(iv) An estimate of the potential total hydrocarbon emissions (if you monitor the cooling water for leaks according to § 63.2490(d)(1)) or monitored substance(s) emissions (if you monitor the cooling water for leaks according to § 63.2490(e)) from the leaking heat exchange system or heat exchanger for each required delay of repair monitoring interval following the procedures in paragraphs (r)(4)(iv)(A) through (D) of this section.

* * * * *

(B) For delay of repair monitoring intervals prior to repair of the leak, calculate the potential total hydrocarbon emissions or monitored substance(s) emissions for the leaking heat exchange system or heat exchanger for the monitoring interval by multiplying the mass emissions rate, determined in § 63.2490(d)(1)(iii)(B) or paragraph (r)(4)(iv)(A) or (D) of this section, 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.

(C) For delay of repair monitoring intervals ending with a repaired leak, calculate the potential total hydrocarbon emissions or monitored substance(s) 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 mass emissions rate 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.

(D) If you monitor the cooling water for leaks according to § 63.2490(e), you must calculate the mass emissions rate by determining the mass flow rate of the cooling water at the monitoring location where the leak was detected. Cooling water mass flow rates may be determined using direct measurement, pump curves, heat balance calculations, or other engineering methods. Once determined, multiply the mass flow rate of the cooling water by the concentration of the measured substance(s).

* * * * *

■ 31. Amend § 63.2550 by revising the entry "In ethylene oxide service" to read as follows:

§ 63.2550 What definitions apply to this subpart?

* * * * *

In ethylene oxide service means the following:

(1) For equipment leaks, any equipment that contains or contacts a fluid (liquid or gas) that is at least 0.1 percent by weight of ethylene oxide. If information exists that suggests ethylene

oxide could be present in equipment, the equipment is considered to be ''in ethylene oxide service'' unless sampling and analysis is performed as specified in § 63.2492 to demonstrate that the equipment does not meet the definition of being ''in ethylene oxide service''. Examples of information that could suggest ethylene oxide could be present in equipment, include calculations based on safety data sheets, material balances, process stoichiometry, or previous test results provided the results are still relevant to the current operating conditions.

(2) For process vents, each batch and continuous process vent in a process that, when uncontrolled, contains a concentration of greater than or equal to 1 ppmv undiluted ethylene oxide, and when combined, the sum of all these process vents would emit uncontrolled ethylene oxide emissions greater than or equal to 5 lb/yr (2.27 kg/yr). If information exists that suggests ethylene oxide could be present in a batch or continuous process vent, then the batch or continuous process vent is considered to be ''in ethylene oxide service'' unless an analysis is performed as specified in § 63.2492 to demonstrate that the batch or continuous process vent does not meet the definition of being ''in ethylene oxide service''. Examples of information that could suggest ethylene oxide could be present in a batch or continuous process vent, include calculations based on safety data sheets, material balances, process stoichiometry, or previous test results provided the results are still relevant to the current operating conditions.

(3) For storage tanks, storage tanks of any capacity and vapor pressure storing a liquid that is at least 0.1 percent by weight of ethylene oxide. If knowledge exists that suggests ethylene oxide could be present in a storage tank, then the storage tank is considered to be ''in ethylene oxide service'' unless the procedures specified in § 63.2492 are performed to demonstrate that the storage tank does not meet the definition of being ''in ethylene oxide service''. The exemptions for ''vessels storing organic liquids that contain HAP only as impurities'' and ''pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere'' listed in the definition of ''storage tank'' in this section do not apply for storage tanks that may be in ethylene oxide service. Examples of information that could suggest ethylene oxide could be present in a storage tank, include calculations based on safety data sheets, material balances, process stoichiometry, or previous test results provided the results are still relevant to the current operating conditions.

* * * * *

■ 32. Revise table 10 to subpart FFFF of part 63 to read as follows:

Table 10 to Subpart FFFF of Part 63—Work Practice Standards for Heat Exchange Systems

As required in § 63.2490, you must meet each requirement in the following table that applies to your heat exchange systems:

For each . . .	You must . . .
Heat exchange system, as defined in § 63.101.	a. Comply with the requirements of § 63.104 and the requirements referenced therein, except as specified in § 63.2490(b) and (c); or b. Comply with the requirements in § 63.2490(d); or c. Comply with the requirements in § 63.2490(e).

■ 33. Amend table 12 to subpart FFFF of part 63 by revising entry ''63.9(k)'' to read as follows:

Table 12 to Subpart FFFF of Part 63—Applicability of General Provisions to Subpart FFFF

* * * * *

Citation	Subject	Explanation
* * *	* *	* *
§ 63.9(k)	Electronic reporting procedures	Yes.
* * *	* *	* *

[FR Doc. 2024–05906 Filed 4–3–24; 8:45 am]

BILLING CODE 6560–50–P

Title 40 —Protection of Environment

Chapter I —Environmental Protection Agency

Subchapter C —Air Programs

Part 63 —National Emission Standards for Hazardous Air Pollutants for Source Categories

Authority: 42 U.S.C. 7401 *et seq.*

Source: 57 FR 61992, Dec. 29, 1992, unless otherwise noted.

Subpart O—Ethylene Oxide Emissions Standards for Sterilization Facilities

Source: 89 FR 24172, Apr. 5, 2024, unless otherwise noted.

§ 63.360 Applicability.

(a) You are subject to the requirements of this subpart if you own or operate a sterilization facility that has an affected source specified in paragraph (b) of this section. Table 6 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

(b) The affected sources subject to this subpart are:

(1) Each SCV at any sterilization facility;

(2) Each ARV at any sterilization facility;

(3) Each CEV at any sterilization facility;

(4) The collection of all Group 1 room air emissions at any sterilization facility; and

(5) The collection of all Group 2 room air emissions at any sterilization facility.

(c) An existing affected source is one the construction or reconstruction of which was commenced on or before April 13, 2023.

(d) A new affected source is one the construction or reconstruction of which is commenced after April 13, 2023.

(e) An SCV, ARV, or CEV is reconstructed if you meet the reconstruction criteria as defined in § 63.2, and if you commence reconstruction after April 13, 2023.

(f) This subpart does not apply to beehive fumigators.

(g) This subpart does not apply to research or laboratory facilities as defined in section 112(c)(7) of title III of the Clean Air Act Amendment of 1990.

(h) This subpart does not apply to EtO sterilization operations at stationary sources such as hospitals, doctor's offices, clinics, or other facilities whose primary purpose is to provide medical or dental services to humans or animals.

(i) 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 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 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.

(j) You must comply with the provisions of this subpart no later than the dates specified in paragraphs (j)(1) through (17) of this section:

(1) If you own or operate an existing affected source, you must comply with the applicable provisions of this subpart no later than the dates specified in tables 1 through 5 to this subpart, as applicable.

(2) If you own or operate a new affected source, and the initial startup of your affected source is on or before April 5, 2024, you must comply with the provisions of this subpart no later than April 5, 2024.

(3) If you own or operate a new affected source, and the initial startup is after April 5, 2024, you must comply with the provisions of this subpart upon startup of your affected source.

(4) If existing SCV, ARV, or CEV or parts of an existing collection of Group 1 or Group 2 room air emissions are replaced such that the replacement meets the definition of reconstruction in § 63.2 and the reconstruction commenced after April 13, 2023, then the existing affected source becomes a new affected source. The reconstructed source must comply with the requirements for a new affected source upon initial startup of the reconstructed source or by April 5, 2024, whichever is later.

(5) All existing SCVs at facilities that meet or exceed 1 tpy of EtO use within any consecutive 12-month period after April 7, 2025, that increase their EtO use after April 6, 2026, such that the SCV becomes subject to a more stringent emission standard, immediately upon becoming subject to the more stringent emission standard.

(6) All existing SCVs at facilities that do not exceed 1 tpy of EtO use within any consecutive 12-month period after April 6, 2026, that increase their EtO use thereafter, such that the SCV becomes subject to a more stringent emission standard, immediately upon becoming subject to the more stringent emission standard.

(7) All new SCVs at facilities that increase their EtO use over a year after startup such that the SCV becomes subject to a more stringent emission standard, immediately upon becoming subject to the more stringent emission standard.

(8) All existing ARVs at facilities that meet or exceed 10 tpy of EtO use within any consecutive 12-month period after April 7, 2025, that increase their EtO use after April 6, 2026, such that the ARV becomes subject to a more stringent emission standard, immediately upon becoming subject to the more stringent emission standard.

(9) All existing ARVs at facilities that do not exceed 10 tpy of EtO use within any consecutive 12-month period after April 6, 2026, that increase their EtO use after thereafter, such that the ARV becomes subject to a more stringent emission standard, immediately upon becoming subject to the more stringent emission standard.

(10) All new ARVs at facilities that increase their EtO use over a year after startup such that the ARV becomes subject to a more stringent emission standard, immediately upon becoming subject to the more stringent emission standard.

(11) All existing CEVs at facilities that do not exceed 60 tpy of EtO use within any consecutive 12-month period after April 6, 2026, that increase their EtO use thereafter, such that the CEV becomes subject to a more stringent emission standard, immediately upon becoming subject to the more stringent emission standard.

(12) All new CEVs at facilities that increase their EtO use over a year after startup such that the CEV becomes subject to a more stringent emission standard, immediately upon becoming subject to the more stringent emission standard.

(13) All existing collections of Group 1 room air emissions at facilities that do not exceed 40 tpy of EtO use within any consecutive 12-month period after April 6, 2026, that increase their EtO use thereafter, such that the collection of Group 1 room air emissions becomes subject to a more stringent emission standard, immediately upon becoming subject to the more stringent emission standard.

(14) All new Group 1 room air emissions at facilities that increase their EtO use over a year after startup such that the Group 1 room air emissions become subject to a more stringent emission standard, immediately upon becoming subject to the more stringent emission standard.

(15) All existing collections of Group 2 room air emissions at facilities that meet or exceed 4 tpy of EtO use within any consecutive 12-month period after April 7, 2025, that increase their EtO use after April 6, 2026, such that the collection of Group 2 room air emissions becomes subject to a more stringent emission standard, immediately upon becoming subject to the more stringent emission standard.

(16) All existing collections of Group 2 room air emissions at facilities that do not exceed 4 tpy of EtO use within any consecutive 12-month period after April 6, 2026, that increase their EtO use thereafter, such that the collection of Group 2 room air emissions becomes subject to a more stringent emission standard, immediately upon becoming subject to the more stringent emission standard.

(17) All new Group 2 room air emissions at facilities that increase their EtO use over a year after startup such that the Group 2 room air emissions become subject to a more stringent emission standard, immediately upon becoming subject to the more stringent emission standard.

§ 63.361 Definitions.

Terms and nomenclature used in this subpart are defined in the Clean Air Act (the Act) as amended in 1990, §§ 63.2 and 63.3, or in this section. For the purposes of this subpart, 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.

Acid-water scrubber means an add-on air pollution control device that uses an aqueous or alkaline scrubbing liquor to absorb and neutralize acid gases.

Aeration means, for the purposes of this rule, exposing sterilized material at elevated temperatures to drive EtO out of the material.

Aeration room means any vessel or room that is used to facilitate off-gassing of EtO at a sterilization facility. If a facility uses only combination sterilization units, for the purposes of this rule, there are no aeration rooms at the facility.

Aeration room vent (ARV) means the point(s) through which the evacuation of EtO-laden air from an aeration room occurs. For combination sterilization units, there is no ARV.

Catalytic oxidizer means a combustion device that uses a solid-phase catalyst to lower the temperature required to promote the oxidization and achieve adequate reduction of volatile organic compounds, as well as volatile hazardous air pollutants.

Chamber exhaust vent (CEV) means the point(s) through which EtO-laden air is removed from the sterilization chamber during chamber unloading following the completion of sterilization and associated air washes. This may also be referred to as a “backvent” (or “back vent”). For combination sterilization units, there is no CEV.

Combination sterilization unit means any enclosed vessel in which both sterilization and aeration of the same product occur within the same vessel, *i.e.,* the vessel is filled with ethylene oxide gas or an ethylene oxide/ inert gas mixture for the purpose of sterilizing and is followed by aeration of ethylene oxide.

Combined emission stream means when the emissions from more than one emission source are routed together using common ductwork prior to the control system.

Continuous monitoring system (CMS) means, for the purposes of this rule, the equipment necessary to continuously samples the regulated parameter specified in § 63.364 or § 63.365 of this subpart without interruption, evaluates the detector response at least once every 15 seconds, and computes and records the average value at least every 60 seconds, except during allowable periods of calibration and except as defined otherwise by the continuous emission monitoring system (CEMS) performance specifications (PS) in appendix B to part 60 of this chapter.

Control System Residence Time means the time elapsed from entrance of flow into the control system until gaseous materials exit the control system. For control systems with multiple exhaust streams whereby the residence time may vary for the streams, the residence time for purposes of complying with this subpart means the longest residence time for any exhaust stream in use. If a peak shaver is used, it is part of the control system, and its residence time must be considered.

Deviation means any instance in which an owner or operator of an affected source, subject to this subpart:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limitation, parameter value, or best management practice; or

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart or that is included in the operating permit for any facility required to obtain such a permit.

EtO dispensing means charging a sterilization chamber or chambers with EtO from non-cartridge storage media (*e.g.,* drums, cylinders) via the use of piping, lines, and other equipment. This includes injection rooms and post-injection handling of containers.

Gas/solid reactor means an add-on air pollution control device that uses a dry, solid-phase system to chemically convert EtO so that it becomes bound to the solid packing. This may also be referred to as a "dry bed reactor" or a "dry bed scrubber."

Group 1 room air emissions mean emissions from indoor EtO storage, EtO dispensing, vacuum pump operations, and pre-aeration handling of sterilized material.

Group 2 room air emissions mean emissions from post-aeration handling of sterilized material.

Indoor EtO storage means the storage of EtO within non-cartridge media (*e.g.,* drums, cylinders) inside a sterilization building.

Initial startup means the moment when an affected source subject to an emissions standard in § 63.362 first begins operation.

Injection room means any room where EtO is injected into containers (*e.g.,* bags, pouches) that are filled with product to be sterilized.

Maximum ethylene glycol concentration means the concentration of ethylene glycol in the scrubber liquor of an acid-water scrubber control device established during a performance test when the scrubber achieves the appropriate control of EtO emissions.

Maximum gas/solid reactor pressure drop means the pressure drop of the gas/solid reactor established during a performance test when the gas/solid reactor achieves the appropriate control of EtO emissions.

Maximum liquor tank level means the level of scrubber liquor in the acid-water scrubber liquor recirculation tank established during a performance test when the scrubber achieves the appropriate control of EtO emissions.

Maximum scrubber liquor pH means the pH of the acid-water scrubber liquor established during a performance test when the scrubber achieves the appropriate control of EtO emissions.

Minimum stack volumetric flow rate means the stack volumetric flow rate corrected established during a compliance demonstration when permanent total enclosure (PTE) requirements are met.

Minimum temperature at the inlet to the catalyst bed means the temperature at the inlet to the catalyst bed established during a performance test when the catalytic oxidizer achieves the appropriate control of EtO emissions.

Minimum temperature difference across the catalyst bed means the temperature difference across the catalyst bed established during a performance test when the catalytic oxidizer achieves the appropriate control of EtO emissions.

Minimum temperature in or immediately downstream of the firebox means the temperature in or immediately downstream of the firebox established during a performance test when the thermal oxidizer achieves the appropriate control of EtO emissions.

Natural draft opening (NDO) means any permanent opening in the enclosure that remains open during operation of the facility and is not connected to a duct in which a fan is installed.

Operating day means any day that a facility is engaged in a sterilization operation.

Peak shaver means a device that is used to reduce high EtO concentrations within an exhaust stream such that the downstream control device is not overwhelmed.

Permanent total enclosure (PTE) means a permanently installed enclosure that meets the criteria of Method 204 of appendix M, 40 CFR part 51 for a PTE. A PTE completely surrounds a source of emissions such that all EtO emissions are captured, contained, and directed to a control system or to an outlet(s).

Post-aeration handling of sterilized material means the storage and transportation of material that has been removed from aeration but has not been placed in a vehicle for the sole purpose of distribution to another facility. Post-aeration handling of sterilized material ends when that vehicle is closed for the final time before leaving the facility. This definition does not include handling of material that has been both previously sterilized and not removed from aeration following re-sterilization.

Post-injection handling of containers means the storage and transportation of containers (*e.g.,* bags, pouches) that have been injected with EtO but have not been placed in a sterilization chamber.

Pre-aeration handling of sterilized material means the storage and transportation of material that has been removed from a sterilization chamber but has not been placed in an aeration room. If only combination sterilization units are used, and if material is not moved out of the vessel between sterilization and aeration, then emissions from this source do not exist. This does not include post-injection handling of containers.

Rolling sum means the weighted sum of all data, meeting QA/QC requirements or otherwise normalized, collected during the applicable rolling time period. The period of a rolling sum stipulates the frequency of data collection, summing, and reporting. As an example, to demonstrate compliance with a rolling 30-operating day sum emission reduction standard determined from hourly data, you must

(1) determine the total mass of ethylene oxide prior to control and following control for each operating day;

(2) then sum the current daily total mass prior to control with the previous 29 operating day total mass values and repeat the same process for the current daily total mass following control; and

(3) then divide the 30-operating day total mass emissions following control by the 30-operating day total mass prior to control and subtract the resulting value from one to obtain the 30-operating day emission reduction achieved.

Single-item sterilization means a process in which one or more items are placed in a pouch, EtO is injected into the pouch, and the sealed pouch is placed in a vessel to allow sterilization to occur.

Sterilization chamber means any enclosed vessel or room that is filled with EtO gas, or an EtO/inert gas mixture, for the purpose of sterilizing and/or fumigating at a sterilization facility. This does not include injection rooms.

Sterilization chamber vent (SCV) means the point (prior to the vacuum pump) through which the evacuation of EtO from the sterilization chamber occurs following sterilization or fumigation, including any subsequent air washes.

Sterilization facility means any stationary source where EtO is used in the sterilization or fumigation of materials, including but not limited to facilities that engage in single-item sterilization.

Sterilization operation means any time when EtO is removed from the sterilization chamber through the SCV or the chamber exhaust vent, when EtO is removed from the aeration room through the aeration room vent, when EtO is stored within the building, when EtO is dispensed from a container to a chamber, when material is moved from sterilization to aeration, or when materials are handled post-aeration.

Thermal oxidizer means all combustion devices except flares.

Vacuum pump operation means the operation of vacuum pumps, excluding dry seal vacuum pumps, for the purpose of removing EtO from a sterilization chamber.

§ 63.362 Standards.

(a) ***Compliance date.*** If you own or operate an affected source, you must comply with the applicable requirement by the compliance date specified in § 63.360(j). The standards of this section are summarized in tables 1 through 5 to this subpart.

(b) ***Applicability of standards.*** The standards in paragraphs (c) through (k) of this section apply at all times. If using EtO CEMS to determine compliance with an applicable standard, this compliance demonstration is based on the previous 30-operating days of data. If using EtO CEMS to determine compliance with an applicable emission reduction standard in paragraphs (c) through (g) and (i) of this section for each operating day, you must determine the total inlet mass to and outlet mass from the control system using the procedures laid out in § 63.364(f) and appendix A to this subpart, and you must maintain the emission limit based on the inlet mass and the applicable emission reduction standard. If using EtO CEMS to determine compliance with an applicable emission reduction standard in paragraph (j) of this section, you must continuously comply with the requirements of that paragraph.

(c) ***SCV.*** You must comply with each applicable standard in table 1 to this subpart, and you must meet each applicable requirement specified in § 63.363. If a SCV is combined with a stream from another emission source, you must comply with the appropriate emission standard as prescribed in paragraph (i) of this section.

(d) ***ARV.*** You must comply with each applicable standard in table 2 to this subpart, and you must meet each applicable requirement specified in § 63.363. If an ARV is combined with a stream from another emission source, you must comply with the appropriate emission standard as prescribed in paragraph (i) of this section.

(e) ***CEV.*** You must comply with each applicable standard in table 3 to this subpart, and you must meet each applicable requirement specified in § 63.363. If a CEV is combined with a stream from another emission source, you must comply with the appropriate emission standard as prescribed in paragraph (i) of this section.

(f) ***Group 1 room air emissions.*** You must comply with the applicable standard in table 4 to this subpart, and you must meet each applicable requirement specified in § 63.363. If Group 1 room air emissions are combined with a stream from another emission source, you must comply with the appropriate emission standard as prescribed in paragraph (i) of this section.

(g) ***Group 2 room air emissions.*** You must comply with the applicable standard in table 5 to this subpart, and you must meet each applicable requirement specified in § 63.363. If Group 2 room air emissions are combined with a stream from another emission source, you must comply with the appropriate emission standard as prescribed in paragraph (i) of this section. If you are required to limit the sterilization chamber concentration of EtO to 1 ppmv prior to opening the sterilization chamber door, you must meet the monitoring requirements specified in § 63.364(h).

(h) ***Capture systems.*** Room air emissions for which numerical limits are prescribed must be captured and routed under negative pressure to a control system. You may assume the capture system efficiency is 100 percent if both conditions in paragraphs (h)(1) and (2) of this section are met:

(1) The capture system meets the criteria in Method 204 of appendix M to 40 CFR part 51 for a PTE and directs all the exhaust gases from the enclosure to an add-on control system.

(2) All sterilization operations creating exhaust gases for which the compliance demonstration is applicable are contained within the capture system.

(i) ***Requirements for combined emission streams.*** When streams from two or more emission sources are combined, you must demonstrate compliance by either the approach specified in paragraph (i)(1) of this section or the approach specified in paragraph (i)(2) of this section in lieu of the applicable standards in paragraphs (c) through (g) of this section for the affected source. The combined emission stream limit is based on as 30-operating day rolling sum. In order to elect to comply with a combined emission streams limit, you must use a CEMS on each exhaust stack at the facility to determine compliance.

(1) ***Monitoring after emission streams are combined.*** You must follow requirements of paragraphs (i)(1)(i) through (iii) of this section to determine the applicable combined emission streams limitation and demonstrate compliance. Under this approach, you must first determine the 30-operating day rolling sum of mass inlet to the control system. Then, the emission limitation is determined by applying the most stringent emission reduction standard to the 30-operating day rolling sum of the inlet mass. You must maintain actual emissions at or below that rate. For example, suppose a facility controls all of its ARVs and CEVs with one control system and that the emission reduction standards that apply to the ARVs and CEVs are 99.9% and 99%, respectively. Further suppose that the mass of uncontrolled EtO emissions from the combined stream is 5 lb during the 30-operating day period. Under this approach, the facility would need to apply an emission reduction of 99.9% to the combined stream, resulting in an emission limit of 0.005 lb for the 30-operating day period.

(i) The combined emission streams limit for each 30-operating day period is determined daily by using equation 1 to this paragraph.

Equation 1 to paragraph (i)(2)(i)

$$CES_{Combined} = M_{30day} * (1 - Max(ER)) \qquad \text{(Eq. 1)}$$

Where:

$CES_{Combined}$ = The combined emission stream limit based upon monitoring after the emission streams are combined, in pounds.

M_{30day} = The 30-operating day total mass sent to controls for the combined emission stream (*i.e.*, monitoring data at the inlet of the control system), as calculated using equation A-3 and determined in accordance with appendix A to this subpart. The term “M_{30day}” as used in this equation is equivalent to the term “E_{30day}” as designated in equation A-3.

Max(ER) = The most stringent emission reduction standard specified in tables 1 through 5 of this subpart applicable to any of the constituent streams, in decimal format.

(ii) The 30-operating day rolling sum of emissions for the combined emission stream (*i.e.*, monitoring data at the outlet of the control system) is calculated daily using equation A-3 and determined in accordance with appendix A to this subpart. For purposes of this section, this value is designated as $E_{Combined}$. If the combined emission stream is split between two or more control systems, further sum the 30-operating day rolling sum of emissions from each control system to obtain $E_{Combined}$.

(iii) Compliance with the combined emission streams limitation shall be determined by demonstrating that $E_{Combined}$, as calculated in accordance with paragraph (i)(1)(ii) of this section, for each 30-operating day period is at or below $CES_{Combined}$, as calculated in paragraph (i)(1)(i) of this section.

(2) ***Monitoring before emission streams are combined.*** You must follow requirements of paragraphs (i)(2)(i) through (iii) of this section to determine the applicable combined emission streams limitation and demonstrate compliance. Under this approach, you must first determine 30-operating day rolling sum of inlet mass to the control system for each component stream. Then, the emission limitation is determined by applying the applicable emission reduction standards to the 30-operating day rolling sum of each component stream and summing across the components. You must maintain actual emissions at or below that rate. For example, suppose a facility controls all of its ARVs and CEVs with one control system and that the emission reduction standards that apply to the ARVs and CEVs are 99.9% and 99%, respectively. Further suppose that during a 30-operating day period the mass of uncontrolled EtO emissions from the ARVs is 4 lb and the mass of uncontrolled EtO emissions from the CEVs is 1 lb. Under this approach, the facility would need to apply an emission reduction of 99.9% to the ARV stream and an emission reduction of 99% to the CEV stream, resulting in an emission limit of 0.014 lb for the 30-operating day period.

(i) The combined emission streams limit for each 30-operating day period is determined daily by using equation 2 to this paragraph.

Equation 2 to paragraph (i)(2)(i)

$$CES_{Streams} = \sum_{i=1}^{n} (M_{c,i} * (1 - ER_i)) + \sum_{j=1}^{m} (M_{c,j} * (1 - ER_j)) \quad \text{(Eq. 2)}$$

Where:

$CES_{Streams}$ = The combined emission stream limit based upon monitoring before the emission streams are combined, in pounds.

$M_{c,i}$ = The 30-operating day total mass sent to controls for each non-SCV constituent emission stream (*i.e.,* monitoring data at the inlet of the control system), as calculated using equation A-3 and determined in accordance with appendix A to this subpart. The term “$M_{c,i}$” as used in this equation is equivalent to the term “E_{30day}” as designated in equation A-3.

ER_i = The applicable emission reduction standard from tables 2 through 5 of this subpart to each non-SCV constituent emission stream *i*.

i = Non-SCV constituent emission stream index.

n = Total number of non-SCV constituent emission streams.

$M_{c,j}$ = The 30-operating day total mass sent to controls for each SCV emission stream, as determined in accordance with equation 10 of § 63.364(f)(1)(i)(C)(*1*).

ER_j = The applicable SCV emission reduction standard in table 1 to this subpart, in decimal format.

j = SCV emission stream index.

m = Total number of SCV emission streams.

(ii) The 30-operating day rolling sum emissions for the combined emission stream (*i.e.,* monitoring data at the outlet of the control system) is calculated daily using equation A-3 and determined in accordance with appendix A to this subpart. For purposes of this section, this value is designated as $E_{Combined}$. If the combined emission stream is split between two or more control systems, then further sum the 30-operating day rolling sum emissions from each control system to obtain $E_{Combined}$.

(iii) Compliance with the combined emission streams limitation shall be determined by demonstrating that $E_{Combined}$, as calculated in accordance with paragraph (i)(2)(ii) of this section, for each 30-operating day period is at or below $CES_{Streams}$, as calculated paragraph (i)(2)(i) of this section.

(3) If room air emissions are both subject to an emission standard and split between two or more control systems, then these control systems must be treated as part of the same control system.

(j) ***Site-wide emission limitation.*** You may choose to comply with a site-wide emission limitation (SWEL) specified in this paragraph (j) in lieu of the applicable standards in paragraphs (c) through (g) of this section for the facility. The SWEL, which is calculated daily, is based on the previous 30 operating days of data. In order to elect to comply with a SWEL, you must utilize an EtO CEMS on each exhaust stack at the facility to determine compliance. The owner or operator may demonstrate compliance via one of the two SWEL approaches in lieu of the applicable standard(s) in paragraphs (c) through (g) of this section for the facility. If electing to comply with a SWEL, you must comply with paragraph (j)(3) of this section.

(1) ***SWEL based upon facility EtO use.*** If you elect to comply with a SWEL based upon facility EtO use, you must follow requirements of paragraphs (j)(1)(i) through (iii) of this section to determine the applicable SWEL and demonstrate compliance. Under this approach, you first determine the 30-operating day rolling sum of EtO use. The SWEL is determined by multiplying by 0.99 and then applying the required SCV percent emission reduction standard in table 1 to this subpart to the 30-operating day rolling sum of EtO usage. Then, for each CEMS at the outlet of the control systems at the facility, determine the 30-operating day rolling sum of emissions. Finally, determine the facility actual emissions by summing the 30-operating day rolling sums for each CEMS at the facility. You must maintain actual emissions at or below the SWEL.

(i) The SWEL for each 30-operating day period is determined daily by using equation 3 to this paragraph.

Equation 3 to paragraph (j)(1)(i)

$$SWEL_{Fac} = M_{Fac} * 0.99 * (1 - ER_{SCV}) \qquad \text{(Eq. 3)}$$

Where:

$SWEL_{Fac}$ = SWEL based upon facility EtO use, in pounds.

M_{Fac} = Facility EtO use over the previous 30 operating days, in pounds, as determined in accordance with equation 11 of § 63.364(i)(2).

0.99 = Adjustment factor for EtO residual in sterilized product.

ER_{SCV} = The applicable SCV emission reduction standard in table 1 to this subpart, in decimal format.

(ii) The 30-operating day rolling sum of emissions are determined daily using equation 4 to this paragraph.

Equation 4 to paragraph (j)(1)(ii)

$$E_{Fac} = \sum_{i=1}^{n} E_{o,i} \qquad \text{(Eq. 4)}$$

Where:

E_{Fac} = The total emissions from the facility over the previous 30-operating days, in pounds.

$E_{o,i}$ = The 30-operating day rolling sum of emissions calculated at each exhaust stack, *i*, monitored by an EtO CEMS, as calculated using equation A-3 of appendix A to this subpart.

i = Exhaust stack index

n = Total number of exhaust stacks

(iii) Compliance with the SWEL based upon facility EtO usage shall be determined by demonstrating that E_{Fac}, as calculated in accordance with paragraph (j)(1)(ii) of this section, for each 30-operating day period is at or below the SWEL, as calculated paragraph (j)(1)(i) of this section.

(2) ***SWEL based upon emissions streams.*** If you elect to comply with a SWEL based upon emissions streams, you must follow requirements of paragraphs (j)(2)(i) through (iii) of this section to determine the applicable SWEL and demonstrate compliance. Under this approach, for each non-SCV affected source, you must determine the mass of EtO sent to controls and apply the applicable emission reduction standard. For each SCV affected source, you must determine the mass of EtO sent to controls as specified in § 63.364(f)(1)(i)(C)(*1*) and apply the applicable emission reduction standard. The SWEL is determined by summing across the result of this calculation for each affected source (both non-SCV and SCV). Then, for each CEMS at the outlet of the control system(s) at the facility, determine the 30-operating day rolling sum of emissions. Finally, determine the facility actual emissions by summing the 30-operating day rolling sums for each CEMS at the facility. You must maintain actual emissions at or below the SWEL.

(i) The SWEL for each 30-operating day period is determined daily by using equation 5 to this paragraph.

Equation 5 to paragraph (j)(2)(i)

$$SWEL_{Streams} = \sum_{i=1}^{n} (M_{c,i} * (1 - ER_i)) + \sum_{j=1}^{m} (M_{c,j} * (1 - ER_j)) \qquad \text{(Eq. 5)}$$

Where:

$SWEL_{Streams}$ = SWEL based upon individual emissions streams, in pounds.

$M_{c,i}$ = The 30-operating day total mass sent to controls (*i.e.,* monitoring data at the inlet of the control system) for each non-SCV emission stream, as calculated using equation A-3 and determined in accordance with appendix A to this subpart. The term "$M_{c,i}$" as used in this equation is equivalent to the term "E_{30day}" as designated in equation A-3.

ER_i = The applicable emission reduction standard to each non-SCV emission stream, *i*, specified in tables 1 through 5 of this subpart, in decimal format.

i = Non-SCV emission streams index.

n = Total number of non-SCV emission streams.

$M_{c,j}$ = The 30-operating day total mass sent to controls for each SCV emission stream, as determined in accordance with equation 10 in § 63.364(f)(1)(i)(C)(*1*).

ER_j = The applicable SCV emission reduction standard in table 1 to this subpart, in decimal format.

j = SCV emission stream index.

m = Total number of SCV emission streams.

(ii) The 30-operating day rolling sum of emissions are determined daily using equation 4 to this section.

(iii) Compliance with the SWEL based upon emission streams shall be determined by demonstrating that E_{Fac}, as calculated in accordance with paragraph (j)(2)(ii) of this section, for each 30-operating day period is at or below $SWEL_{Streams}$, as calculated in paragraph (j)(2)(i) of this section.

(3) ***Boundary.*** The boundary for this approach includes all affected sources at the facility.

(k) ***General duty.*** 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 the owner or 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.

§ 63.363 Compliance and performance provisions.

(a) ***Continuous compliance.*** You must demonstrate continuous compliance with the applicable emission standard(s) using an EtO CEMS, including a shared EtO CEMS, installed and operated in accordance with the requirements of Performance Specification 19 in appendix B and Procedure 7 in appendix F to part 60 of this chapter. Alternatively, if you own or operate a facility where EtO use is less than 100 pounds/yr, you may demonstrate continuous compliance by conducting annual performance tests using the performance testing requirements in § 63.7, according to the applicability in table 6 to this subpart, the procedures listed in this section, and the test methods listed in § 63.365. If you elect to demonstrate compliance through periodic performance testing, you must also demonstrate continuous compliance with each operating limit required under this section according to the methods specified in § 63.364. If you own or operate an area source facility where EtO use is less than 100 pounds/yr where an existing collection of Group 2 room air emission is operated in accordance with the PTE requirements of EPA Method 204 of appendix M to part 51 of this chapter, you may instead conduct these performance tests once every three years.

(b) ***Initial compliance for Facilities that use EtO CEMS.*** To demonstrate initial compliance with an emission standard using a CEMS that measures HAP concentrations directly (*i.e.,* an EtO CEMS), the initial performance test must consist of the first 30 operating days after the certification of the CEMS according to Performance Specification 19 in Appendix B to part 40 of this chapter. The initial compliance demonstration period must be completed on or before the date that compliance must be demonstrated (*i.e.,* 180 days after the applicable compliance date). You must follow the procedures in appendix A to this subpart.

(1) The CEMS performance test must demonstrate compliance with the applicable EtO standards in tables 1 through 5 to this subpart. Alternatively, the CEMS performance test may demonstrate compliance with § 63.362(i) or (j).

(i) You may time-share your CEMS among different measurement points provided that:

(A) The measurement points are approximately equidistant from the CEMS;

(B) The sampling time at each measurement point is at least 3 times as long as the CEMS response time;

(C) The CEMS completes at least one complete cycle of operation for each shared measurement point within a 15-minute period; and

(D) The CEMS meets the other requirements of PS 19.

(2) You must collect hourly data from auxiliary monitoring systems during the performance test period, to convert the pollutant concentrations to pounds per hour.

(c) ***Initial compliance demonstration where facility EtO use is less than 100 pounds per year.*** If you own or operate an affected source that is both subject to an emission standard in § 63.362 and located within a facility where EtO use is less than 100 pounds per year, you may comply with paragraphs (c)(1) and (2) of this section:

(1) Conduct an initial compliance demonstration using the procedures listed in § 63.7 of this part according to the applicability in table 6 to this subpart, the procedures listed in this section, and the test methods listed in § 63.365;

(2) Complete the initial compliance demonstration within 180 days after the compliance date for the affected source as determined in § 63.360(j).

(d) ***Operating limits for facility where EtO use is less than 100 lb/yr.*** If annual EtO use at the facility is less than 100 lb, the procedures in paragraphs (d)(1) through (5) of this section may be used to determine compliance with the standard(s) under § 63.362(c) through (g) and to establish operating limits for each of the control devices, as applicable:

(1) You must determine the percent emission reduction of the control system used to comply with § 63.362(c) through (g) using the test methods and procedures in § 63.365(d)(1).

(2) If an acid-water scrubber(s) is used to comply with a standard, then you must establish as an operating limit:

(i) The maximum ethylene glycol concentration using the procedures described in § 63.365(e)(1)(i);

(ii) The maximum liquor tank level using the procedures described in § 63.365(e)(1)(ii); or

(iii) The maximum scrubber liquor pH using the procedures described in § 63.365(e)(1)(iii).

(3) If a thermal oxidizer(s) is used to comply with a standard, you must establish as an operating limit the minimum temperature in or immediately downstream of the firebox using the procedures described in § 63.365(e)(2).

(4) If a catalytic oxidizer(s) is used to comply with the standard, you must establish as operating limits both:

(i) The minimum temperature at the inlet to the catalyst bed using the procedures described in § 63.365(e)(3); and

(ii) The minimum temperature difference across the catalyst bed using the procedures described in § 63.365(e)(3).

(5) If a gas/solid reactor(s) is used to comply with the standard, you must establish as an operating limit the pressure drop across the media beds and conduct weekly sampling and analysis of the media. Determine the maximum gas/solid reactor pressure drop using the procedures described in § 63.365(e)(4).

(e) ***Other control technology for facility where EtO use is less than 100 lb/yr.*** If you are conducting a performance test using a control technology other than an acid-water scrubber, catalytic oxidizer, thermal oxidizer, or gas/solid reactor, you must provide to the Administrator information describing the design and operation of the air pollution control system, including recommendations for the parameters to be monitored that will demonstrate continuous compliance. Based on this information, the Administrator will determine the parameter(s) to be measured during the performance test. During the performance test required in paragraph (a) of this section, using the methods approved in § 63.365(e)(5), you must determine the site-specific operating limit(s) for the operating parameters approved by the Administrator. You must submit the information at least sixty days before the performance test is scheduled to begin. The information on the control technology must include the five items listed in paragraphs (1) through (5) of this section:

(1) Identification of the specific parameters you propose to use as additional operating limits;

(2) A discussion of the relationship between these parameters and emissions of regulated pollutants, identifying how emissions of regulated pollutants change with changes in these parameters and how limits on these parameters will serve to limit emissions of regulated pollutants;

(3) A discussion of how you will establish the upper and/or lower values which will establish the operating limits for these parameters;

(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.

(f) ***Other emission streams.*** If the emission stream does not consist only of an SCV(s), the procedures in paragraphs (f)(1) through (3) of this section shall be used to determine initial compliance with the emission limits under § 63.362(d) through (g), as applicable:

(1) You must comply with paragraph (c) of this section, as applicable.

(2) If you are complying with a percent emission reduction standard as specified in tables 1 through 5 to this subpart, you must determine compliance with § 63.362(c) through (g), as applicable, using the test methods and procedures in § 63.365(d)(1).

(3) If you are required to operate any portion of the facility under PTE, you must initially demonstrate that the PTE meets the requirements of Method 204 of 40 CFR part 51, appendix M, and that all exhaust gases from the enclosure are delivered to a control system or stack(s). You must also meet the requirements in § 63.363(f)(3)(i) and either § 63.363(f)(3)(ii) or (iii):

(i) Maintain direction of the airflow into the enclosure at all times, verifying daily using the procedures described in § 63.364(f)(5) and meet either of the requirements.

(ii) Establish as an operating limit the *minimum volumetric flow rate through the affected stack(s)* using the procedures described in § 63.365(f)(1); or

(iii) Install, operate, calibrate, and maintain a continuous pressure differential monitoring system using the procedures described in § 63.364(f)(4).

§ 63.364 Monitoring requirements.

(a) ***General requirements.***

(1) If you own or operate an affected source subject to an emission standard in § 63.362, you must comply with the monitoring requirements in § 63.8, according to the applicability in table 6 to this subpart, and in this section.

(2) If you own or operate an affected source at a facility where EtO use is less than 100 lb/yr that is subject to an emission standard in § 63.362, you may monitor the parameters specified in paragraphs (b), (c), (d), (e), (g), and (i) of this section. All monitoring equipment shall be installed such that representative measurements of emissions or process parameters from the source are obtained. For monitoring equipment purchased from a vendor, verification of the operational status of the monitoring equipment shall include completion of the manufacturer's written specifications or recommendations for installation, operation, and calibration of the system.

(3) If you own or operate an affected source that is subject to an emission standard in § 63.362 and that is required to monitor using EtO CEMS, you must comply with paragraphs (f), (g), and (i) of this section.

(4) If you comply with the management practice for Group 2 room air emissions at area sources, you must comply with paragraph (h) of this section.

(5) You must keep the written procedures required by § 63.8(d)(2) on record 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).

(b) ***Acid-water scrubbers.*** If you are demonstrating continuous compliance through periodic performance testing on an acid-water scrubber(s), you must:

(1) ***Ethylene glycol concentration.*** Sample the scrubber liquor from the acid-water scrubber(s) and analyze and record at least once per week the ethylene glycol concentration of the scrubber liquor using the test methods and procedures in § 63.365(e)(1). Monitoring is required during a week only if the scrubber unit has been operated. You must maintain the weekly ethylene glycol concentration below the operating limit established during the most recent performance test;

(2) ***Scrubber liquor tank level.*** Measure and record at least once per day the level of the scrubber liquor in the recirculation tank(s). You must install, maintain, and use a liquid level indicator to measure the scrubber liquor tank level (*i.e.*, a marker on the tank wall, a dipstick, a magnetic indicator, etc.). Monitoring is required during a day only if the scrubber unit has been operated. You must maintain the daily scrubber liquor height in each recirculation tank below the applicable operating limit established during the most recent performance test; or

(3) ***pH.*** Monitor and record at least every 15 minutes the scrubber liquor pH. Monitoring is required when the scrubber is operating. A data acquisition system for the pH monitor shall compute and record each 3-hour average scrubber liquor pH value, rolled hourly. This must be done by first averaging the scrubber liquor pH readings obtained over a clock hour, *i.e.*, beginning and ending on the hour. All data collected during the operating hour must be used, even if the scrubber unit is not operating for a complete hour. Then, the average of the previous 3 operating hours must be calculated to determine the 3-hour rolling average scrubber liquor pH. You must maintain the 3-hour rolling average scrubber liquor pH below the applicable operating limit established during the most recent performance test. You must ensure the pH monitoring system meets the following requirements:

(i) The pH sensor must be installed in a position that provides a representative measurement of scrubber liquor pH;

(ii) The sample must be properly mixed and representative of the fluid to be measured; and

(iii) 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 must be conducted in accordance with your monitoring plan at the time of each performance test but no less frequently than quarterly.

(c) ***Oxidizers.*** If you are demonstrating continuous compliance through periodic performance testing on a catalytic oxidizer or thermal oxidizer, the requirements in paragraphs (c)(1) and (2) of this section apply:

(1) For thermal oxidizers, you must monitor and record at least every 15 minutes the temperature in or immediately downstream of the firebox using the temperature monitor described in paragraph (c)(4) of this section. Monitoring is required when the thermal oxidizer is operating. A data acquisition system for the temperature monitor shall compute and record each 3-hour average temperature value, rolled hourly. This must be done by first averaging the temperature readings over a clock hour, *i.e.*, beginning and ending on the hour. All data collected during the operating hour must be used, even if the thermal oxidizer is not operating for a complete hour. Then, the average of the previous 3 operating hours must be calculated to determine the 3-hour rolling average temperature in or immediately downstream of the firebox. You must maintain the 3-hour rolling average temperature above the operating limit established during the most recent performance test.

(2) For catalytic oxidizers, you must monitor and record at least every 15 minutes the temperature at the inlet to the catalyst bed using the temperature monitor described in paragraph (c)(4) of this section. Monitoring is required when the catalytic oxidizer is operating. A data acquisition system for the temperature monitor shall compute and record each 3-hour average temperature, rolled hourly. This must be done by first averaging the temperature readings over a clock hour, *i.e.*, beginning and

ending on the hour. All data collected during the operating hour must be used, even if the catalytic oxidizer is not operating for a complete hour. Then, the average of the previous 3 operating hours must be calculated to determine the 3-hour rolling average temperature at the inlet to the catalyst bed. You must maintain the 3-hour rolling average temperature above the operating limit established during the most recent performance test.

(3) For catalytic oxidizers, you must monitor and record at least every 15 minutes the temperature increase across the catalyst bed, immediately downstream of the catalytic bed, using the temperature monitor described in paragraph (c)(4) of this section. Monitoring is required when the catalytic oxidizer is operating. A data acquisition system for the temperature monitor shall compute and record each 3-hour average temperature increase, rolled hourly. This must be done by first computing the difference in outlet temperature minus inlet temperature (monitored under paragraph (c)(2)), and second averaging the temperature difference values over a clock hour, *i.e.,* beginning and ending on the hour. All data collected during the operating hour must be used, even if the catalytic oxidizer is not operating for a complete hour. Then, the average of the previous 3 operating hours must be calculated to determine the 3-hour rolling average temperature increase across the catalyst bed. You must maintain the 3-hour average temperature increase above the operating limit established during the most recent performance test.

(4) You must install, calibrate, operate, and maintain a temperature monitor with a minimum accuracy of ±1 percent over the normal range of the temperature measured, expressed in degrees Celsius, or 2.8 degrees Celsius, whichever is greater. You must verify the accuracy of the temperature monitor twice each calendar year at least five months apart with a reference temperature monitor (traceable to National Institute of Standards and Technology (NIST) standards or an independent temperature measurement device dedicated for this purpose). During accuracy checking, the probe of the reference device shall be at the same location as that of the temperature monitor being tested. As an alternative, the accuracy of the temperature monitor may be verified in a calibrated oven (traceable to NIST standards).

(5) For catalytic oxidizers, if the monitor indicates that the temperature is below the operating limit, within 7 calendar days you must:

(i) Correct the temperature or temperature increase so that it falls within the established operating range; or

(ii) Replace the catalyst bed. Following replacement of the catalyst bed, you must conduct a new performance test within 180 days and re-establish the operating limits.

(d) ***Gas-solid reactors.*** If you are demonstrating continuous compliance through periodic performance testing on a gas/solid reactor(s), you must:

(1) ***Media analysis.*** Sample the media from the gas/solid reactor(s) and have the manufacturer analyze at least once per week. Monitoring is required during a week only if the gas/solid reactor unit has been operated; and

(2) ***Pressure drop.*** Monitor and record at least every 15 minutes the pressure drop. Monitoring is required when the gas/solid reactor is operating. A data acquisition system for the pressure drop monitor shall compute and record each 3-hour average gas/solid reactor pressure drop value, rolled hourly. This must be done by first averaging the gas/solid reactor pressure drop readings obtained over a clock hour, *i.e.,* beginning and ending on the hour. All data collected during the operating hour must be used, even if the gas/solid reactor unit is not operating for a complete hour. Then, the

average of the previous 3 operating hours must be calculated to determine the 3-hour rolling average gas/solid reactor pressure drop. You must maintain the 3-hour rolling average gas/solid reactor pressure drop below the applicable operating limit established during the most recent performance test.

(e) ***Performance testing, other control technology.*** If you are complying with § 63.363(d) or (e) using periodic performance testing and the use of a control device other than acid-water scrubbers, catalytic or thermal oxidizers, or gas/solid reactors, you must monitor the parameters as approved by the Administrator using the methods and procedures in § 63.365(e).

(f) ***EtO CEMS configurations.*** If you are using EtO CEMS to demonstrate compliance with an emission standard, you must install and operate an EtO CEMS on each outlet for the control system in accordance with the requirements of Appendix A to subpart O of this part. You must also conduct monitoring for each inlet to the control system that is used to demonstrate compliance with the emission reduction standard in accordance with the requirements of appendix A to this subpart, with the exception for SCV emission streams to the control system.

(1) ***EtO CEMS inlet configuration.*** The following caveats apply:

(i) ***SCVs.*** If you do not own or operate a single-item sterilizer, to demonstrate compliance with the percent emission reduction standards for emissions streams that are comprised only of SCVs, you may use the following procedures as an alternative to monitoring the inlet emission stream to determine the mass emissions of EtO being emitted via sterilization chamber(s) vents prior to the controls.

(A) Determine the mass ($M_{SCV,n}$) of EtO used for each charge and at each sterilization chamber used during the previous 30 days using the procedures in either paragraph (f)(1)(i)(A)(*1*) or (*2*) of this section.

(*1*) Weigh the EtO gas cylinder(s) used to charge the sterilizer(s) before and after charging. Record these weights to the nearest 45 g (0.1 lb) and calculate the theoretical mass (M_c) vented to the controls using equation 1 to this paragraph.

Equation 1 to paragraph (f)(1)(i)(A)(1)

$$M_{SCV,n} = M_{charge} \times \%EO_w \qquad \text{(Eq. 1)}$$

Where:

$M_{SCV,n}$ = Theoretical total mass of EtO vented to controls per charge, g (lb)

M_{charge} = total mass of sterilizer gas charge, g (lb)

$\%EO_w$ = weight percent of EtO

(*2*) Install a calibrated rate meter at the sterilizer inlet(s) and continuously measure the flow rate (Q_m) and duration of each sterilizer charge. Calculate the theoretical mass ($M_{SCV,n}$) vented to the controls using equation 2 to this paragraph.

Equation 2 to paragraph (f)(1)(i)(A)(2)

$$M_{SCV,n} = (Q_m \text{ x } T_n \text{ x } \%EO_v \text{ x } \frac{MW}{SV}) \quad \text{(Eq. 2)}$$

Where:

$M_{SCV,n}$ = theoretical total mass of EtO sent to controls per charge

Q_m = volumetric flow rate, liters per minute (L/min) corrected to 20 °C and 101.325 kilopascals (kPa) (scf per minute (scfm) corrected to 68 °F and 1 atmosphere of pressure (atm))

T_n = time duration of each charge, min

$\%EO_v$ = volume fraction percent of EtO

n = number of EtO charges

MW = molecular weight of EtO, 44.05 grams per gram-mole (g/g-mole) (44.05 pounds per pound-mole (lb/lb-mole))

SV = standard volume, 24.05 liters per gram-mole (L/g-mole) at 20 °C and 101.325 kPa (385.1 scf per pound-mole (scf/lb-mole) at 68 °F and 1 atm).

(B) Determine the adjustment factor (*f*) using equation 8 to this paragraph. Determine the mass of EtO sent to controls from all non-SCV affected sources, *I*, using equation 4 to this paragraph. For facilities where EtO use is less than 4 tpy, if not all Group 2 room air emissions are routed to a control device, do not include Group 2 room air emissions in *I*, and subtract 0.002 from this factor.

Equations 3 and 4 to paragraph (f)(1)(i)(B)

$$f = 0.99 - \frac{I}{M_{Fac}} \quad \text{(Eq. 3)}$$

Where:

f = Adjustment factor.

I = Mass of non-SCV EtO routed to control devices over the previous 30 operating days

M_{Fac} = Facility EtO use over the previous 30-operating days, in pounds, as determined in accordance with equation 11 of § 63.364(i)(2)

$$I = \sum_{i=1}^{n} M_{c,i} \qquad \text{(Eq. 4)}$$

Where:

I = Mass of non-SCV EtO routed to control devices over the previous 30 operating days

$M_{c,i}$ = The 30-operating day total mass sent to controls (*i.e.*, monitoring data at the inlet of the control system) for each non-SCV emission stream, as calculated using equation A-3 and determined in accordance with appendix A to this subpart. The term “$M_{c,i}$” as used in this equation is equivalent to the term “E_{30day}” as designated in equation A-3.

i = Non-SCV emission stream index.

n = Total number of non-SCV emission streams.

(C)

(*1*) Determine the mass rate of EtO sent to controls during the previous 30 days using equation 5 to this paragraph.

Equation 5 to paragraph (f)(1)(i)(C)(1)

$$M_{SCV} = f \times \sum_{i=1}^{n} M_{SCV,n} \qquad \text{(Eq. 5)}$$

Where:

M_{SCV} = Total mass of EtO sent to controls over the previous 30 operating days, g/hr (lb/hr)

f = Adjustment factor

$M_{SCV,n}$ = Theoretical mass of EtO sent to controls per charge per chamber, g (lb)

n = Total number of charges during the previous 30 operating days

(*2*) If both this approach is chosen and the SCV is (or SCVs are) combined with another emission stream, then the owner or operator cannot monitor the point after the combination occurs.

(ii) ***Room air emissions.*** If room air emissions are both subject to an emission standard and split between two or more control systems, then monitoring must be conducted for room air emissions before they are combined with other streams.

(2) ***EtO CEMS on exhaust configurations.*** Exhaust gases from the emission sources under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration, or a main stack plus a bypass stack. For the CEMS used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

(i) ***Single unit-single stack configurations.*** For an emission source that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(ii) ***Unit utilizing common stack with other emission source(s).*** When an emission source utilizes a common stack with one or more other emission sources, but no emission sources not subject to this rule, you shall either:

(A) Install the required CEMS in the duct from each emission source, leading to the common stack; or

(B) Install the required CEMS in the common stack.

(iii) ***Unit(s) utilizing common stack with non-commercial sterilization emission source(s).***

(A) When one or more emission sources shares a common stack with one or more emission sources not subject to this rule, you shall either:

(*1*) Install the required CEMS in the ducts from each emission source that is subject to this rule, leading to the common stack; or

(*2*) Install the required CEMS described in this section in the common stack and attribute all of the emissions measured at the common stack to the emission source(s).

(B) If you choose the common stack monitoring option:

(*1*) For each hour in which valid data are obtained for all parameters, you must calculate the pollutant emission rate; and

(*2*) You must assign the calculated pollutant emission rate to each of the units subject to the rule that share the common stack.

(iv) ***Unit with multiple parallel control devices with multiple stacks.*** If the exhaust gases from an emission source, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, you shall install the required CEMS described in each of the multiple stacks. You shall calculate hourly, flow-weighted, average pollutant emission rates for the unit as follows:

(A) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters;

(B) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly gas flow rate at that stack or duct;

(C) Sum the products determined under paragraph (f)(2)(iv)(B) of this section; and

(D) Divide the result obtained in paragraph (f)(2)(I(C) of this section by the total hourly gas flow rate for the unit, summed across all of the stacks or ducts.

(g) ***PTE monitoring.*** If you are required to operate all or a portion of your sterilization facility under PTE conditions, you must:

(1) ***Initial compliance.*** Demonstrate initial procedures in § 63.365(g)(1) and continued compliance with the provisions in this section. You must follow the requirements of either paragraphs (g)(2) and (3) of this section or paragraph (g)(4) of this section.

(2) ***Continuous compliance.*** If you choose to demonstrate continuous compliance through volumetric flow rate monitoring, you must monitor and record at least every 15 minutes the volumetric flow rate from each outlet where air from the PTE is sent using a flow rate monitoring system described in paragraph (g)(3) of this section. Monitoring is required when the portion of the facility covered by PTE is operated. A data acquisition system for the flow rate monitoring system shall compute and record each 3-hour average flow rate value, rolled hourly. This must be done by first averaging the flow rate readings over a clock hour, *i.e.,* beginning and ending on the hour. All data collected during the operating hour must be used, even the portion of the facility covered by PTE is not operated for a complete hour. Then, the average of the previous 3 operating hours must be calculated to determine the 3-hour rolling average flow rate. You must maintain the 3-hour rolling average flow rate above the applicable operating limits established during the most recent compliance demonstration.

(3) ***Continuous flow rate monitoring system for PTE.*** You must install, operate, calibrate, and maintain instruments, according to the requirements in paragraphs (g)(3)(i) through (ix) of this section, for continuously measuring and recording the stack gas flow rate to allow determination of compliance with the minimum volumetric flow rate through the affected stack operating limit(s).

(i) You must install each sensor of the flow rate monitoring system in a location that provides representative measurement of the exhaust gas flow rate. The flow rate sensor is that portion of the system that senses the volumetric flow rate and generates an output proportional to that flow rate.

(ii) The flow rate monitoring system must be designed to measure the exhaust flow rate over a range that extends from a value of at least 20 percent less than the lowest expected exhaust flow rate to a value of at least 20 percent greater than the highest expected exhaust flow rate.

(iii) The flow rate monitoring system must be equipped with a data acquisition and recording system that is capable of recording values over the entire range specified in paragraph (g)(3)(ii) of this section.

(iv) The signal conditioner, wiring, power supply, and data acquisition and recording system for the flow rate monitoring system must be compatible with the output signal of the flow rate sensors used in the monitoring system.

(v) The flow rate monitoring system must be designed to complete a minimum of one cycle of operation for each successive 15-minute period.

(vi) The flow rate sensor must have provisions to determine the daily zero and upscale calibration drift (CD) (*see* sections 3.1 and 8.3 of Performance Specification 2 in appendix B to Part 60 of this chapter for a discussion of CD).

(A) Conduct the CD tests at two reference signal levels, zero (*e.g.,* 0 to 20 percent of span) and upscale (*e.g.,* 50 to 70 percent of span).

(B) The absolute value of the difference between the flow monitor response and the reference signal must be equal to or less than 3 percent of the flow monitor span.

(vii) You must perform an initial relative accuracy test of the flow rate monitoring system according to section 8.2 of Performance Specification 6 of appendix B to part 60 of the chapter with the exceptions in paragraphs (g)(3)(vii)(A) and (B) of this section.

(A) The relative accuracy test is to evaluate the flow rate monitoring system alone rather than a continuous emission rate monitoring system.

(B) The relative accuracy of the flow rate monitoring system shall be no greater than 10 percent of the mean value of the reference method data.

(viii) You must verify the accuracy of the flow rate monitoring system at least once per year by repeating the relative accuracy test specified in paragraph (g)(3)(vii) of this section.

(ix) You must operate the flow rate monitoring system and record data during all periods of operation of the affected facility including periods of startup, shutdown, and malfunction.

(4) ***Pressure differential monitor.*** You must instead install, operate, calibrate, and maintain a continuous pressure differential monitoring system, as follows, to verify the presence of PTE. You must operate this system whenever the facility is in operation. You must also maintain the pressure differential at or above 0.007 inches of water over a three-hour rolling average.

(i) This monitoring system must measure the pressure differential between the interior and exterior of the PTE, with at least one monitoring device located in each room that borders the PTE. These monitoring devices shall be designed to provide measurements of pressure differential to at least the nearest 0.001 inches of water and having a complete cycle time no greater than 5 minutes.

(ii) A data acquisition system for the monitoring system shall compute and record each 3-hour average pressure differential value, rolled hourly. This must be done by first averaging the pressure differential readings over a clock hour, *i.e.,* beginning and ending on the hour. All data collected during the operating hour must be used, even in portions of the facility covered by PTE that are not operated for a complete hour. Then, the average of the previous 3 operating hours must be calculated to determine the 3-hour rolling average pressure differential. If data are not recorded from an alternative monitoring device, during any malfunction of the principal monitoring device(s) or the automatic recorder, you must manually record the measured data at least hourly.

(h) ***Sterilization chamber end-cycle EtO concentration.*** As part of your monitoring plan, you must document your approach for determining the EtO sterilization chamber concentration. If you choose a parametric approach you must meet the requirements in paragraph (h)(1) of this section and if you choose a direct measurement approach you must meet the requirements in paragraph (h)(2) of this section. Alternatively, you may petition the administrator for an alternative monitoring approach under § 63.8(f).

(1) If you choose a parametric approach for determining chamber EtO concentrations you must document parameter(s) used in the calculation to determine of EtO concentrations and the calculation(s) used to determine the chamber concentration. Any instrumentation used for parametric monitoring must also be identified in the monitoring plan and at a minimum this plan should include the following for each instrument:

(i) Parameter measured and measurement principle of the monitor.

(ii) Instrument name, model number, serial number, and range.

(iii) Manufacturer recommended operation practices, including daily operational check.

(iv) Procedures for calibration, the frequency of calibration, and accuracy requirements of the calibration.

(v) Description for how the information from the parameter monitor is being collected and stored.

(2) If you choose a direct measurement approach for determining chamber EtO calibrations you must document the procedures used for the operation of the instruments. Any instrument used for direct measurement of EtO must be identified in the monitoring plan and at a minimum this plan must include the following information:

(i) Instrument name, model number, serial number, and range.

(ii) Description of the measurement principle and any potential interferences.

(iii) If applicable, the description of the sampling condition system.

(iv) Procedures for calibration, the frequency of calibration, and accuracy requirements of the calibration.

(v) Description for how the information from the parameter monitor is being collected and stored.

(i) ***EtO usage.*** If you own or operate a sterilization facility subject to the requirements of this subpart you must monitor and record on a daily basis the daily and 30-operating day EtO usage according to the requirements of this paragraph. Additionally, you must record EtO usage for each calendar month.

(1) Monitor and record on a daily basis, the daily total mass of ethylene oxide, in pounds, used at the facility. The daily total mass must be determined using the methodology specified in § 63.365(c)(1)(i) and (ii).

(2) Determine and record daily the 30-operating day rolling ethylene oxide usage rate using equation 6 to this paragraph.

Equation 6 to paragraph (i)(2)

$$M_{Fac} = \sum_{i=1}^{30} m_{Fac,i} \qquad \text{(Eq. 6)}$$

Where:

M_{Fac} = Facility EtO use over the previous 30 operating days, in pounds.

$m_{Fac,i}$ = Daily EtO use for operating day *i*, in pounds, as determined in accordance with paragraph (i)(1) of this section

> i = Operating day index.

(3) Determine and record the total mass of EtO used in each calendar month.

§ 63.365 Test methods and procedures.

(a) *General —*

(1) ***Performance testing for facility where EtO use is less than 100 pounds per year.*** If you own or operate an affected source at a facility where EtO use is less than 100 lb/yr that is subject to an emission standard in § 63.362, you must comply with the performance testing requirements in § 63.7, according to the applicability in table 6 to this subpart, using the methods in paragraph (b) or (c) of this section, following the applicable procedures for initial compliance and continuous compliance in paragraphs (d), (e), and (f) of this section.

(2) ***Facilities subject to capture efficiency.*** If you are subject to capture efficiency requirements in § 63.362, you must follow the applicable procedures for initial and continuous compliance in paragraph (f) of this section.

(b) ***Test methods for facility where EtO use is less than 100 pounds per year.*** You must use the following test methods to determine the average mass emissions of EtO in lb/hr at the inlet of a control system ($M_{APCD, i}$) and/or outlet of a control system or stack ($E_{APCD, o}$).

(1) Select the location of the sampling ports and the number of traverse points according to Method 1 of appendix A-1 to part 60 of this chapter. Alternatively, for ducts less than 0.3 meter (12 in.) in diameter, you may choose to locate sample ports according to Method 1A of appendix A-1 to part 60 of this chapter.

(2) Determine the flow rate through the control system exhaust(s) continuously during the test period according to either Methods 2, 2A, or 2C of appendix A-1 to part 60 of this chapter, as appropriate. If using Method 2, 2A, or 2C, you must complete velocity traverses immediately before and subsequently after each test run. If your test run is greater than 1 hour, you must also complete a velocity traverse at least every hour. Average the velocity collected during a test run and calculate volumetric flow as outlined in the appropriate method.

(3) Determine the oxygen and carbon dioxide concentration of the effluent according to Method 3A or 3B of appendix A-2 to part 60 of this chapter. The manual procedures (but not instrumental procedures) of voluntary consensus standard ANSI/ASME PTC 19.10-1981 (incorporated by reference, see § 63.14) may be used as an alternative to EPA Method 3B.

(4) Determine the moisture content of the stack gas according to Method 4 of appendix A-3 to part 60 of this chapter. Alternatively, you may use an on-line technique that has been validated using Method 301 of appendix A to this part.

(5) Determine the EtO concentration according to either paragraph (b)(5)(i) or (ii) of this section.

(i) Follow Method 320 of appendix A to this part and the following paragraphs (5)(i)(A) through (D).

(A) The instrumentation used for measurement must have the measurement range to properly quantify the EtO in the gas stream. Additionally, for outlet emission streams, the instrumentation must have a method detection limit an order of magnitude below concentration equivalent of the emission limit.

(B) Instrumentation used must be continuous in nature with an averaging time of one minute or less.

(C) Calibration Spectra and all other analyte spiking required in the method must use EtO gaseous cylinder standard(s) which meet the criteria found in Performance Specification 19 of appendix B to part 60 if this chapter.

(D) Other methods and materials may be used; however, these alternative test methods are subject to Administrator approval.

(ii) Alternatively, ASTM D6348-12 (Reapproved 2020), (incorporated by reference, see § 63.14) may be used with the following conditions:

(A) The test plan preparation and implementation in the Annexes to ASTM D 6348-12 (R2020), Sections A1 through A8 are mandatory; and

(B) In ASTM D6348-12 (R2020) 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 equation 1 to this paragraph:

Equation 1 to paragraph (b)(5)(ii)

Reported Results = ((Measured Concentration in Stack))/(%R) x 100.]

(6) Calculate the mass emission of EtO by using equations 2 and 3 to this paragraph:

Equations 2 and 3 to paragraph (b)(6)

$$M_{APCD,in} = \frac{C_{Eto,i} \text{ x } Q_i \text{ x } 44.05}{385.1 \text{ x } 10^6} \qquad \text{(Eq. 2)}$$

$$E_{APCD,o} = \frac{C_{EtO,o} \text{ x } Q_o \text{ x } 44.05}{385.1 \text{ x } 10^9} \qquad \text{(Eq. 3)}$$

Where:

$M_{APCD,\,i}$ = average inlet mass rate of EtO per hour, lb/hr

$C_{EtO,i}$ = inlet EtO concentration, ppmdv.

Qi = average inlet volumetric flow per hour at standard conditions, dscf/hr

44.05 = molecular weight (MW) of EtO, lb/lb-mole

> $MW/385.1 \times 10^6$ = conversion factor, from ppmv at standard conditions to lb/cf
>
> $E_{APCD,o}$ = average outlet mass rate of EtO per hour, lb/hr
>
> $C_{EtO,o}$ = outlet EtO concentration, ppbdv.
>
> Q_o = average outlet volumetric flow per hour at standard conditions, dscf/hr
>
> $MW/385.1 \times 10^9$ = conversion factor, from ppbv at standard conditions to lb/cf

(c) ***Alternative approach for SCVs for facility where EtO use is less than 100 pounds per year.*** If you do not own or operate a single-item sterilizer, to demonstrate compliance with the percent emission reduction standards for emissions streams that are comprised only of SCVs, you may use the following procedures as an alternative to paragraph (b) of this section to determine the mass emissions of EtO being emitted via sterilization chamber(s) vents prior to the controls.

(1) Determine the mass ($M_{SCV,n}$) of EtO used for each charge and at each sterilization chamber used during the performance tests using the procedures in either paragraph (c)(1)(i) or (ii) of this section.

(i) Weigh the EtO gas cylinder(s) used to charge the sterilizer(s) before and after charging. Record these weights to the nearest 45 g (0.1 lb) and calculate the theoretical mass ($M_{SCV,n}$) vented to the controls using equation 4 to this paragraph.

Equation 4 to paragraph (c)(1)(i)

$$M_{SCV,n} = M_{charge} \text{ x } \%EO_w \qquad \text{(Eq. 4)}$$

> Where:
>
> $M_{SCV,n}$ = Theoretical total mass of EtO vented to controls per charge, g (lb) M_{charge} = total mass of sterilizer gas charge, g (lb) $\%E.O._w$ = weight percent of EtO

(ii) Install a calibrated rate meter at the sterilizer inlet(s) and continuously measure the flow rate (Q_m) and duration of each sterilizer charge. Calculate the theoretical mass ($M_{SCV,n}$) vented to the controls using equation 5 to this paragraph.

Equation 5 to paragraph (c)(1)(ii)

$$M_{SCV,n} = \left(Q_m \text{ x } T_n \text{ x } \%EO_v \text{ x } \frac{MW}{SV}\right) \qquad \text{(Eq. 5)}$$

> Where:
>
> $M_{SCV,n}$ = Total mass of EtO sent to controls per charge Q_m = volumetric flow rate, liters per minute (L/min) corrected to 20 °C and 101.325 kilopascals (kPa) (scf per minute (scfm) corrected to 68 °F and 1 atmosphere of pressure (atm)) T_n = time duration of each charge, min $_n$ = number of EtO charges $\%E.O._v$ = volume fraction percent of EtO MW = molecular weight of EtO, 44.05 grams per gram-mole (g/g-mole) (44.05 pounds per pound-mole (lb/lb-mole)) SV = standard volume, 24.05

> liters per gram-mole (L/g-mole) at 20 °C and 101.325 kPa (385.1 scf per pound-mole (scf/lb-mole) at 68 °F and 1 atm).

(2) Determine the mass rate of EtO sent to controls during the performance test using equation 6 to this paragraph.

Equation 6 to paragraph (c)(2)

$$M_{SCV} = \frac{\sum_{i=1}^{n} M_{SCV,n}}{T_t} \times f \qquad \text{(Eq. 6)}$$

> Where:
>
> M_{SCV} = Total mass of EtO sent to controls per hour, g/hr (lb/hr) $M_{SCV,n}$ = Total mass of EtO sent to controls per charge per chamber, g (lb) T_t = Total time of the performance test, hour n = Total number of charges during testing period f = Portion of EtO use that is assumed to be routed to the control system (0.93 if aeration is conducted in separate vessel; 0.98 otherwise)

(d) ***Compliance determination for facility where EtO use is less than 100 pounds per year.*** Each compliance demonstration shall consist of three separate runs using the applicable methods in paragraph (b) or (c) of this section. To determine compliance with the relevant standard, arithmetic mean of the three runs must be used. These procedures may be performed over a run duration of 1-hour (for a total of three 1-hour runs), except for the SCV testing from this category, where each run shall consist of the entirety of the sterilizer chamber evacuation and subsequent washes. The owner or 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 such conditions represent the entire range of normal operation, including operational conditions for maximum emissions if such emissions are not expected during maximum production. The owner or operator must also account for the control system residence time when conducting the performance test. 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. The following procedures shall be used to demonstrate compliance with a removal efficiency standard. In addition to these procedures, the procedures in paragraph (e) of this section must be followed to establish the operating parameter limits for each applicable emission control(s).

(1) You may determine the mass rate emissions of the stream prior to the control system and at the outlet of the control system using the test methods in paragraph (b) of this section. If the vent stream is comprised only of one or more SCVs, then you may use the procedures in paragraph (c) of this section for the mass rate emissions at the inlet.

(2) Calculate the total mass of EtO per hour that is routed to the control system by summing the mass of EtO per hour from each vent.

(3) Determine percent emission reduction (%ER) using the equation 7 to this paragraph:

Equation 7 to paragraph (d)(3)

$$\%ER = \frac{M_{APCD,i} - E_{APCD,o}}{M_{APCD,i}} \times 100 \qquad \text{(Eq. 7)}$$

Where:

% ER = percent emission reduction $M_{APCD,i}$ = total mass of EtO per hour to the control device $E_{APCD,o}$ = total mass of EtO per hour from the control device

(4) Repeat these procedures two additional times. The arithmetic average percent efficiency of the three runs shall determine the overall efficiency of the control system.

(e) ***Determination of operating limits for control device(s).*** If you are using performance testing to demonstrate compliance with removal efficiency standards, and if you are not demonstrating continual compliance with the applicable standard(s) using an EtO CEMS, you must also determine the operating limit(s) for each control device and then monitor the parameter(s) for each control device. The procedures in the following paragraphs shall be used to establish the parameter operating limits to be continually monitored in § 63.364.

(1) ***Acid-water scrubbers.*** The procedures in paragraph (e)(1) of this section shall be used to determine the operating limits for acid-water scrubbers.

(i) ***Ethylene glycol concentration.*** For determining the ethylene glycol concentration operating limit, you must establish the maximum ethylene glycol concentration as the ethylene glycol concentration averaged over three test runs; use the sampling and analysis procedures in ASTM D3695-88 (incorporated by reference, see § 63.14) to determine the ethylene glycol concentration.

(ii) ***Scrubber liquor tank level.*** During the performance test, you must monitor and record the scrubber liquor tank level to the nearest $^1/_4$ inch at the end of each of the three test runs. Use the data collected during the most recent performance test to calculate the average scrubber liquor tank level. This scrubber liquor tank level is the maximum operating limit for your scrubber liquor tank. Repeat this procedure for every scrubber liquor tank that is included in the performance test.

(iii) ***Scrubber liquor pH.*** During the performance test, you must monitor and record the scrubber liquor pH at least once every 15 minutes during each of the three test runs. You must use pH monitors as described in § 63.364(b)(3). Use the data collected during the most recent performance test to calculate the average scrubber pH measured. This scrubber liquor pH is the maximum operating limit for your acid-water scrubber. Repeat this procedure for every scrubber liquor tank that is included in the performance test.

(2) ***Thermal oxidizers.*** The procedures in this paragraph shall be used to determine the operating limits for thermal oxidizers.

(i) During the performance test, you must monitor and record the temperature at least once every 15 minutes during each of the three test runs. You must monitor the temperature in the firebox of the thermal oxidizer or immediately downstream of the firebox. You must use temperature monitors as described in § 63.364(c)(4).

(ii) Use the data collected during the performance test to calculate and record the average temperature for each test run maintained during the performance test. The average temperature of the test runs is the minimum operating limit for your thermal oxidizer, unless it exceeds the recommended maximum oxidation temperature provided by the oxidation unit manufacturer. If this occurs, the minimum operating limit for your thermal oxidizer consists of the recommended maximum oxidation temperature provided by the oxidation unit manufacturer.

(iii) Paragraphs (e)(2)(i) and (ii) of this section must be completed for each thermal oxidizer that is involved in the performance test.

(3) ***Catalytic oxidizers.*** The procedures in this paragraph shall be used to determine the operating limits for catalytic oxidizers.

(i) Prior to the start of the performance test, you must check the catalyst bed for channeling, abrasion, and settling. If problems are found during the inspection, you must replace the catalyst bed or take other correction action consistent with the manufacturer's recommendations.

(ii) During the performance test, you must monitor and record the temperature at the inlet to the catalyst bed and the temperature difference across the catalyst bed at least once every 15 minutes during each of the three test runs. You must use temperature monitors as described in § 63.364(c)(4).

(iii) Use the data collected during the performance test to calculate and record the average temperature at the inlet to the catalyst bed and the average temperature difference across the catalyst bed maintained for each test run, and then calculate the arithmetic averages of the test runs. These arithmetic averages of the test runs are the minimum operating limits for your catalytic oxidizer, unless it exceeds the recommended maximum oxidation temperature provided by the oxidation unit manufacturer. If this occurs, the minimum operating limit for your catalytic oxidizer consists of the recommended maximum oxidation temperature provided by the oxidation unit manufacturer.

(iv) Paragraphs (e)(3)(i) through (iii) of this section must be completed for each catalytic oxidizer that is involved in the performance test.

(4) ***Gas/solid reactors.*** During the performance test, you must monitor and record the gas/solid reactor pressure drop at least once every 15 minutes during each of the three test runs. Use the data collected during the most recent performance test to calculate the gas/solid reactor pressure measured. This gas/solid reactor pressure is the maximum operating limit for your gas/solid. Repeat this procedure for every gas/solid reactor that is included in the performance test.

(5) ***Other control system for facility where EtO use is less than 100 pounds per year.*** If you seek to demonstrate compliance with a standard found at § 63.362 with a control device other than an acid-water scrubber, catalytic oxidizer, thermal oxidizer, or gas/solid reactor, you must provide to the Administrator the information requested under § 63.363(e). You must submit a monitoring plan that contains the following items: a description of the device; test results collected in accordance with § 63.363(e) verifying the performance of the device for controlling EtO emissions to the atmosphere to the levels required by the applicable standards; the appropriate operating parameters that will be monitored, identifying the ongoing QA procedures and performance specifications that will be conducted on the instruments; the frequency of conducting QA and performance checks; and the frequency of measuring and recording to establish continuous compliance with the standards. Your

monitoring plan is subject to the Administrator's approval. Upon approval by the Administrator you must install, calibrate, operate, and maintain the monitor(s) approved by the Administrator based on the information submitted in your monitoring plan. You must include in your monitoring plan proposed performance specifications and quality assurance procedures for your monitors. The Administrator may request further information and shall approve appropriate test methods and procedures.

(f) ***Determination of compliance with PTE requirement.*** If you are required to operate any portion of your facility with PTE, you must demonstrate initial compliance with the requirements of this subpart by following the procedures of paragraphs (f)(1) through (3) of this section, as applicable, during the initial compliance demonstration or during the initial certification of the CEMS tests.

(1) Determine the capture efficiency by verifying the capture system meets the criteria in section 6 of Method 204 of appendix M to part 51 of this chapter and directs all the exhaust gases from the enclosure to an add-on control device.

(2) Ensure that the air passing through all NDOs flows into the enclosure continuously. If the facial velocities (FVs) are less than or equal to 9,000 meters per hour (492 feet per minute), the continuous inward flow of air shall be verified by continuous observation using smoke tubes, streamers, tracer gases, or other means approved by the Administrator over the period that the volumetric flow rate tests required to determine FVs are carried out. If the FVs are greater than 9,000 meters per hour (492 feet per minute), the direction of airflow through the NDOs shall be presumed to be inward at all times without verification.

(3) If you are demonstrating continuous compliance through monitoring the volumetric flow rate, you must monitor and record the volumetric flow rate (in cubic feet per second) from the PTE through the stack(s) at least once every 15 minutes during each of the three test runs. Use the data collected during the most recent compliance demonstration to calculate the average volumetric flow rate measured during the compliance demonstration. This volumetric flow rate is the minimum operating limit for the stack. Repeat this procedure for every stack that is included in the compliance demonstration.

§ 63.366 Reporting requirements.

(a) ***General requirements.*** The owner or operator of an affected source subject to the emissions standards in § 63.362 must fulfill all reporting requirements in § 63.10(a), (d), (e), and (f), according to the applicability in table 6 to this subpart. These reports will be made to the Administrator at the appropriate address identified in § 63.13 or submitted electronically.

(b) ***Initial compliance report submission.*** You must submit an initial compliance report that provides summary, monitoring system performance, and deviation information to the Administrator on April 5, 2027, or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website for one year, whichever date is later, to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as confidential business information (CBI). Anything submitted using CEDRI cannot later be claimed CBI. You must use the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart. The date report templates become available will be listed on the CEDRI website. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim, submit a complete report, including information claimed to be CBI, to the EPA. The CBI report must be generated using the appropriate form on the CEDRI website or an alternate electronic file consistent with the extensible markup language (XML) schema listed on the CEDRI website. Submit the CBI file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, Attention: Commercial Sterilization Facilities Sector Lead, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph. All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. Reports of deviations from an operating limit shall include all information required in § 63.10(c)(5) through (13), as applicable in table 6 to this subpart, along with information from any calibration tests in which the monitoring equipment is not in compliance with Performance Specification 19 in appendix B and Procedure 7 in appendix F to part 60 of this chapter or the method used for parameter monitoring device calibration. Reports shall also include the name, title, and signature of the responsible official who is certifying the accuracy of the report. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces this requirement. When no deviations have occurred or monitoring equipment has not been inoperative, repaired, or adjusted, such information shall be stated in the report. In addition, the summary report shall include:

(1) The following information:

  (i) Date that facility commenced construction or reconstruction;

  (ii) Hours of commercial sterilization operation over the previous 12 months; and

  (iii) Monthly EtO use, in tons, over the previous 36 months.

  (iv) If you are electing to determine the mass of EtO sent to the control device from the SCV(s) via the procedure in § 63.364(f)(1)(i), you must report the daily EtO use from each applicable chamber for the previous 7 months.

  (v) An indication if you are required to comply with one or more combined emission stream limitations. If so, indicate the affected sources that are included in each combined emission stream limitation.

  (vi) An indication if you are electing to comply with a site-wide emission limit. If you are electing to comply with a site-wide emission limit, report the daily EtO use over the previous 7 months.

(2) If your sterilization facility is demonstrating continuous compliance through periodic performance testing, you must report the following:

  (i) Control system ID;

  (ii) Control device ID;

  (iii) Control device type; and

  (iv) Recirculation tank ID if an acid-water scrubber is used to meet the emission standard and you elect to comply with the maximum scrubber liquor height limit;

(3) You must report the following for each sterilization chamber at your facility:

  (i) The sterilization chamber ID;

(ii) The ID of the control system that the SCV was routed to, if applicable;

(iii) The portion of SCV exhaust that was routed to the control system, if applicable;

(iv) The ID of the EtO CEMS that was used to monitor SCV emissions, if applicable;

(v) The portion of SCV exhaust that was monitored with the EtO CEMS, if applicable;

(vi) The ID of the control system that the CEV was routed to, if applicable;

(vii) The portion of CEV exhaust that was routed to the control system, if applicable;

(viii) The ID of the EtO CEMS that was used to monitor CEV emissions, if applicable;

(ix) The portion of CEV exhaust that was monitored with the EtO CEMS, if applicable;

(4) If emissions from any room in your facility are subject to an emission standard, you must report the following for each room where there is the potential for EtO emissions:

(i) Room ID;

(ii) Documentation of emissions occurring within the room, including aeration, EtO storage, EtO dispensing, pre-aeration handling of sterilized material, and post-aeration handling of sterilized material;

(iii) The ID of the control system that the room air was routed to, if applicable;

(iv) The portion of room air that was routed to the control system, if applicable;

(v) The ID of the EtO CEMS that was used to monitor room air emissions, if applicable;

(vi) The portion of room air that was monitored with the EtO CEMS, if applicable;

(5) If an EtO CEMS was used to demonstrate continuous compliance with an emission standard for more than 30-operating days, you must report the following:

(i) The information specified in section 11 of appendix A to this subpart.

(ii) The affected sources that are included in each inlet that is being monitored with EtO CEMS;

(iii) The IDs of each inlet(s) to and outlet(s) from each control system.

(iv) The daily sum of EtO for each inlet, along with 30-operating day rolling sums.

(v) The daily sum of EtO emissions from each outlet of the control system, along with 30-operating day rolling sums.

(vi) For each day, calculate and report the daily mass emission limit that the control system must achieve based on the previous 30 days of data. For control systems with multiple emission streams, and complying with a combined emission stream limitation in § 63.362(i) or a SWEL in § 63.362(j), report the daily 30-operating day mass emission limit as determined in accordance with CES in § 63.362(i)(1)(i) and (i)(2)(i) or with § 63.362(j)(1)(i) and (j)(2)(i), as applicable.

(vii) For each day, the mass of EtO emitted from the control system over the previous 30 operating days.

(6) If any portion of your facility is required to be operated with PTE, you must report the following:

(i) If you are choosing to demonstrate continuous compliance through the use of volumetric flow rate monitoring, you must report the 3-hr rolling average, rolled hourly volumetric flow from each outlet where air from the PTE is sent, in cubic feet per second.

(ii) If you are choosing to demonstrate continuous compliance through use of differential pressure monitoring, you must report the 3-hr rolling average, rolled hourly pressure differential reading, in inches water.

(7) If you are complying with the requirement to follow the best management practice to limit sterilization chamber concentration of EtO to 1 ppmv prior to opening the sterilization chamber door, you must provide a certification from your responsible official that this approach is being followed and you are meeting the monitoring requirements at § 63.362(h).

(8) If you own or operate an existing collection of Group 2 room air emissions at an area source facility and facility EtO use is less than 4 tpy, you must report the following for each room where there are Group 2 room air emissions:

(i) Room ID;

(ii) Number of room air changes per hour;

(iii) Room temperature, in degrees Celsius; and

(iv) EtO concentration, in ppmv dry basis (ppbvd).

(9) If you own or operate an existing collection of Group 2 room air emissions at an area source facility and EtO use is less than 4 tpy, you are not required to report the information in paragraph (b)(8) of this section if you meet the following requirements:

(i) You are complying with the best management practice to limit sterilization chamber concentration of EtO to 1 ppmv prior to opening the sterilization chamber door; and

(ii) The requirements of § 63.363 are met.

(10) Report the number of deviations to meet an applicable standard. For each instance, report the date, time, the cause and duration of each deviation. For each deviation the report must include a list of the affected sources or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit, and a description of the method used to determine the emissions.

(c) ***Quarterly compliance report submission.*** You must submit compliance reports that provide summary, monitoring system performance, and deviation information to the Administrator within 30 days following the end of each calendar quarter. Beginning on April 5, 2027, or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website for 1 year, whichever date is later, submit all subsequent reports to the EPA via CEDRI, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Anything submitted using CEDRI cannot later be claimed CBI. You must use the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart. The date report templates become available will be listed on the CEDRI website. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim, submit a complete report, including information claimed to be CBI, to the EPA. The CBI report must be generated using the appropriate form on the CEDRI website or an alternate electronic file consistent with the XML schema listed on the CEDRI website. Submit the CBI file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, Attention: Commercial Sterilization Facilities Sector Lead, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph. All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Reports of deviations from an operating limit shall include all information required in § 63.10(c)(5) through (13), as applicable in table 6 to this subpart, and information from any calibration tests in which the monitoring equipment is not in compliance with Performance Specification 19 in appendix B and Procedure 7 in appendix F to part 60 of this chapter or the method used for parameter monitoring device calibration. Reports shall also include the name, title, and signature of the responsible official who is certifying the accuracy of the report. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces this requirement. When no deviations have occurred or monitoring equipment has not been inoperative, repaired, or adjusted, such information shall be stated in the report. In addition, the summary report shall include:

(1) The information listed in paragraphs (b)(1)(i) through (vi) of this section, with the exception that monthly EtO use, in tons, only needs reported for the previous 12 months;

(2) If your sterilization facility is demonstrating continuous compliance through periodic performance testing, you must report the ID for any control system that has not operated since the end of the period covered by the previous compliance report. If a control system has commenced operation since end of the period covered by the previous compliance report, or if any of the information in paragraphs (b)(2)(i) through (iv) of this section has changed for a control system that was included in the previous compliance report, you must report the information in paragraphs (b)(2)(i) through (iv) of this section for those control systems;

(3) You must report the ID for any sterilization chamber that has not operated since then end of the period covered by the previous compliance report. If a sterilization chamber has commenced operation since the end of the period covered by the previous compliance report, or if any of the information in paragraphs (b)(3)(i) through (ix) of this section has changed for a sterilization chamber that was included in the previous compliance report, you must report the information in paragraphs (b)(3)(i) through (ix) of this section for those sterilization chambers;

(4) If emissions from any room in your facility are subject to an emission standard, you must report the ID for any room where there has not been the potential for EtO emissions since the end of the period covered by the previous compliance report. If a room has had the potential for EtO emissions since the end of the period covered by the previous compliance report, or if any of the information in paragraphs (b)(4)(i) through (vi) of this section has changed for a room where there is the potential for EtO emissions that was included in the previous compliance report, you must report the information in paragraphs (b)(4)(i) through (vi) of this section for those rooms;

(5) If an EtO CEMS was used to demonstrate continuous compliance, you must report the information specified in paragraphs (b)(5)(i) through (vi) of this section.

(6) If any portion of your facility is required to be operated with PTE, you must report the information listed in paragraph (b)(6) of this section.

(7) If you are complying with the requirement to follow the best management practice to limit sterilization chamber concentration of EtO to 1 ppmv prior to opening the sterilization chamber door, you must provide a certification from your responsible official that this approach is being followed and you are meeting the monitoring requirements at § 63.362(h).

(8) If you own or operate an existing collection of Group 2 room air emissions at an area source facility and facility EtO use is less than 4 tpy, you must report the ID for any room where Group 2 room air emissions have ceased since end of the period covered by the previous compliance report. If a room has had Group 2 room air emissions since the end of the period covered by the previous compliance report, or if any of the information in paragraphs (b)(8)(i) through (iv) of this section has changed for a room where there are Group 2 room air emissions that were included in the previous compliance report, you must report the information in paragraphs (b)(8)(i) through (iv) of this section for each room where there are Group 2 room air emissions.

(9) If you own or operate an existing collection of Group 2 room air emissions at an area source facility and facility EtO use is less than 4 tpy, you are not required to report the information in paragraph (c)(8) of this section if you meet the requirements in paragraph (b)(9) of this section.

(10) Report the number of deviations to meet an applicable standard. For each instance, report the date, time, the cause, and duration of each deviation. For each deviation, the report must include a list of the affected sources or equipment, the quantity of each regulated pollutant emitted over any emission limit, and a description of the method used to determine the emissions.

(d) ***Construction and reconstruction application.*** You must fulfill all requirements for construction or reconstruction of a facility in § 63.5, according to the applicability in table 6 to this subpart, and in this paragraph.

(1) ***Applicability.***

(i) This paragraph (d) and § 63.5 implement the preconstruction review requirements of section 112(i)(1) for facilities subject to these emissions standards. In addition, this paragraph (d) and § 63.5 include other requirements for constructed and reconstructed facilities that are or become subject to these emissions standards.

(ii) After April 5, 2024, the requirements in this section and in § 63.5 apply to owners or operators who construct a new facility or reconstruct a facility subject to these emissions standards after April 5, 2024. New or reconstructed facilities subject to these emissions standards with an initial startup date before the effective date are not subject to the preconstruction review requirements specified in paragraphs (b)(2) and (3) of this section and § 63.5(d)(3) and (4) and (e).

(2) ***Advance approval.*** After April 5, 2024, whether or not an approved permit program is effective in the jurisdictional authority in which a facility is (or would be) located, no person may construct a new facility or reconstruct a facility subject to these emissions standards, or reconstruct a facility such that the facility becomes a facility subject to these emissions standards, without obtaining advance written approval from the Administrator in accordance with the procedures specified in paragraph (b)(3) of this section and § 63.5(d)(3) and (4) and (e).

(3) ***Application for approval of construction or reconstruction.*** The provisions of paragraph (b)(3) of this section and § 63.5(d)(3) and (4) implement section 112(i)(1) of the Act.

(i) ***General application requirements.***

(A) An owner or operator who is subject to the requirements of paragraph (b)(2) of this section shall submit to the Administrator an application for approval of the construction of a new facility subject to these emissions standards, the reconstruction of a facility subject to these emissions standards, or the reconstruction of a facility such that the facility becomes a facility subject to these emissions standards. The application shall be submitted as soon as practicable before the construction or reconstruction is planned to commence (but not sooner than the effective date) if the construction or reconstruction commences after the effective date. The application shall be submitted as soon as practicable before the initial startup date but no later than 60 days after the effective date if the construction or reconstruction had commenced and the initial startup date had not occurred before the effective date. The application for approval of construction or reconstruction may be used to fulfill the initial notification requirements of paragraph (e)(1)(iii) of this section. The owner or operator may submit the application for approval well in advance of the date construction or reconstruction is planned to commence in order to ensure a timely review by the Administrator and that the planned commencement date will not be delayed.

(B) A separate application shall be submitted for each construction or reconstruction. Each application for approval of construction or reconstruction shall include at a minimum:

(*1*) The applicant's name and address.

(*2*) A notification of intention to construct a new facility subject to these emissions standards or make any physical or operational change to a facility subject to these emissions standards that may meet or has been determined to meet the criteria for a reconstruction, as defined in § 63.2.

(*3*) The address (*i.e.,* physical location) or proposed address of the facility.

(*4*) An identification of the relevant standard that is the basis of the application.

(*5*) The expected commencement date of the construction or reconstruction.

(*6*) The expected completion date of the construction or reconstruction.

(*7*) The anticipated date of (initial) startup of the facility.

(*8*) The type and quantity of hazardous air pollutants emitted by the facility, reported in units and averaging times and in accordance with the test methods specified in the standard, or if actual emissions data are not yet available, an estimate of the type and quantity of hazardous air pollutants expected to be emitted by the facility reported in units and averaging times specified. The owner or operator may submit percent reduction information, if the standard is established in terms of percent reduction. However, operating parameters, such as flow rate, shall be included in the submission to the extent that they demonstrate performance and compliance.

(*9*) Other information as specified in paragraph (b)(3)(ii) of this section and § 63.5(d)(3).

(C) An owner or operator who submits estimates or preliminary information in place of the actual emissions data and analysis required in paragraphs (b)(3)(i)(B)(*8*) and (b)(3)(ii) of this section shall submit the actual, measured emissions data and other correct information as soon as available but no later than with the notification of compliance status required in paragraph (c)(2) of this section.

(ii) ***Application for approval of construction.*** Each application for approval of construction shall include, in addition to the information required in paragraph (b)(3)(i)(B) of this section, technical information describing the proposed nature, size, design, operating design capacity, and method of operation of the facility subject to these emissions standards, including an identification of each point of emission for each hazardous air pollutant that is emitted (or could be emitted) and a description of the planned air pollution control system (equipment or method) for each emission point. The description of the equipment to be used for the control of emissions shall include each control device for each hazardous air pollutant and the estimated control efficiency (percent) for each control device. The description of the method to be used for the control of emissions shall include an estimated control efficiency (percent) for that method. Such technical information shall include calculations of emission estimates in sufficient detail to permit assessment of the validity of the calculations. An owner or operator who submits approximations of control efficiencies under paragraph (b)(3) of this section shall submit the actual control efficiencies as specified in paragraph (b)(3)(i)(C) of this section.

(4) ***Approval of construction or reconstruction based on prior jurisdictional authority preconstruction review.***

(i) The Administrator may approve an application for construction or reconstruction specified in paragraphs (b)(2) and (3) of this section and § 63.5(d)(3) and (4) if the owner or operator of a new or reconstructed facility who is subject to such requirement demonstrates to the Administrator's satisfaction that the following conditions have been (or will be) met:

(A) The owner or operator of the new or reconstructed facility subject to these emissions standards has undergone a preconstruction review and approval process in the jurisdictional authority in which the facility is (or would be) located before the effective date and has received a federally enforceable construction permit that contains a finding that the facility will meet these emissions standards as proposed, if the facility is properly built and operated;

(B) In making its finding, the jurisdictional authority has considered factors substantially equivalent to those specified in § 63.5(e)(1).

(ii) The owner or operator shall submit to the Administrator the request for approval of construction or reconstruction no later than the application deadline specified in paragraph (b)(3)(i) of this section. The owner or operator shall include in the request information sufficient for the Administrator's determination. The Administrator will evaluate the owner or operator's request in accordance with the procedures specified in § 63.5. The Administrator may request additional relevant information after the submittal of a request for approval of construction or reconstruction.

(e) ***Notification requirements.*** The owner or operator of an affected source subject to an emissions standard in § 63.362 shall fulfill all notification requirements in § 63.9, according to the applicability in table 6 to this subpart, and in this paragraph (e).

(1) ***Initial notifications.***

(i) If you own or operate an affected source subject to an emissions standard in § 63.362, you may use the application for approval of construction or reconstruction under paragraph (d)(3)(ii) of this section and § 63.5(d)(3), respectively, if relevant to fulfill the initial notification requirements.

(ii) The owner or operator of a new or reconstructed facility subject to these emissions standards that has an initial startup date after the effective date and for which an application for approval of construction or reconstruction is required under paragraph (d)(3) of this section and § 63.5(d)(3) and (4) shall provide the following information in writing to the Administrator:

(A) A notification of intention to construct a new facility subject to these emissions standards, reconstruct a facility subject to these emissions standards, or reconstruct a facility such that the facility becomes a facility subject to these emissions standards with the application for approval of construction or reconstruction as specified in paragraph (d)(3)(i)(A) of this section;

(B) A notification of the date when construction or reconstruction was commenced, submitted simultaneously with the application for approval of construction or reconstruction, if construction or reconstruction was commenced before the effective date of these standards;

(C) A notification of the date when construction or reconstruction was commenced, delivered or postmarked no later than 30 days after such date, if construction or reconstruction was commenced after the effective date of these standards;

(D) A notification of the anticipated date of startup of the facility, delivered or postmarked not more than 60 days nor less than 30 days before such date; and

(E) A notification of the actual date of initial startup of the facility, delivered or postmarked within 15 calendar days after that date.

(iii) After the effective date, whether or not an approved permit program is effective in the jurisdictional authority in which a facility subject to these emissions standards is (or would be) located, an owner or operator who intends to construct a new facility subject to these emissions standards or reconstruct a facility subject to these emissions standards, or reconstruct a facility such that it becomes a facility subject to these emissions standards, shall notify the Administrator in writing of the intended construction or reconstruction. The notification shall be submitted as soon as practicable before the construction or reconstruction is planned to commence (but no sooner than the effective date of these standards) if the construction or reconstruction commences after the effective date of the standard. The notification shall be submitted as soon as practicable before the initial startup date but no later than 60 days after the effective date of this standard if the construction or reconstruction had commenced and the initial startup date has not occurred before the standard's effective date. The notification shall include all the information required for an application for approval of construction or reconstruction as specified in paragraph (d)(3) of this section and § 63.5(d)(3) and (4). For facilities subject to these emissions standards, the application for approval of construction or reconstruction may be used to fulfill the initial notification requirements of § 63.9.

(2) If an owner or operator of a facility subject to these emissions standards submits estimates or preliminary information in the application for approval of construction or reconstruction required in paragraph (d)(3)(ii) of this section and § 63.5(d)(3), respectively, in place of the actual emissions data or control efficiencies required in paragraphs (d)(3)(i)(B)(*8*) and (b)(3)(ii) of this section, the owner or operator shall submit the actual emissions data and other correct information as soon as available but no later than with the initial notification of compliance status.

(3) If you own or operate an affected source subject to an emissions standard in § 63.362, you must also include the amount of EtO used at the facility during the previous consecutive 12-month period in the initial notification report required by § 63.9(b)(2) and (3). For new sterilization facilities subject to this subpart, the amount of EtO used at the facility shall be an estimate of expected use during the first consecutive 12-month period of operation.

(4) Beginning October 7, 2024, you must submit all subsequent Notification of Compliance Status reports in PDF formatto the EPA following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Commercial Sterilization Sector Lead.

(f) ***Performance test submission.*** Beginning on June 4, 2024, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test following the procedures specified in paragraphs (f)(1) through (3) of this section.

(1) ***Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.*** Submit the results of the performance test to the EPA via the CEDRI, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website.

(2) ***Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.*** The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(3) ***CBI.*** Do not use CEDRI to submit information you claim as CBI. Anything submitted using CEDRI cannot later be claimed CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (f)(1)(i) or (ii) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium 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 file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraphs (f)(1)(i) and (ii) of this section. All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(g) ***Performance evaluation submission.*** Beginning on June 4, 2024, 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 procedures specified in paragraphs (g)(1) through (3) of this section.

(1) ***Performance evaluations of CEMS measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation.*** Submit the results of the performance evaluation to the EPA via CEDRI, which can be accessed through the EPA's CDX. The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website.

(2) ***Performance evaluations of CEMS measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation.*** The results of the performance evaluation must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(3) ***CBI.*** Do not use CEDRI to submit information you claim as CBI. Anything submitted using CEDRI cannot later be claimed CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (g)(1)(i) or (ii) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA. The CBI file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the CBI file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium 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 file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraphs (g)(1)(i) and (ii) of this section. All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(h) ***Extensions for CDX/CEDRI outages.*** If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(i) ***Extensions for force majeure events.*** If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section.

(1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the *force majeure* event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

§ 63.367 Recordkeeping requirements.

(a) If you own or operate an affected source subject to § 63.362, you must comply with the recordkeeping requirements in § 63.10(a) through (c), according to the applicability in table 6 to this subpart, and in this section. All records required to be maintained by this subpart or a subpart referenced by this subpart shall be maintained in such a manner that they can be readily accessed and are suitable for inspection.

(b) You must maintain the previous five years of records specified in § 63.366(b) and (c), as applicable.

(c) You must maintain the previous five years of records for compliance tests and associated data analysis, as applicable.

(d) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

(e) If you are using an EtO CEMS to demonstrate continuous compliance, you must maintain the previous five years of records for all required certification and QA tests.

(f) For each deviation from an emission limit, operating limit, or best management practice, you must keep a record of the information specified in paragraph (g)(1) through (4) of this section. The records shall be maintained as specified in § 63.10(b)(1).

(1) The occurrence and duration of each startup, shutdown, or malfunction of process, air pollution control, and monitoring equipment.

(2) In the event that an affected unit does not meet an applicable standard, record the number of deviations. For each deviation, record the date, time, cause, and duration of each deviation.

(3) For each failure to meet an applicable standard, record and retain a list of the affected sources or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions.

(4) Record actions taken to minimize emissions in accordance with § 63.362(k) and any corrective actions taken to return the affected unit to its normal or usual manner of operation.

§ 63.368 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 whether implementation and enforcement of this subpart are 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 (5) of this section.

(1) Approval of alternatives to the requirements in §§ 63.360 and 63.362.

(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.

(5) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

Table 1 to Subpart O of Part 63—Standards for SCVs

As required in § 63.362(c), for each SCV, you must meet the applicable standard in the following table:

For each . . .	For which . . .	You must . . .	You must comply with the standard . . .
1. Existing SCV	a. Facility EtO use is at least 10 tpy	i. Continuously reduce EtO emissions by 99 percent[1]	Until April 6, 2026.
	b. Facility EtO use is at least 1 tpy but less than 10 tpy	i. Continuously reduce EtO emissions by 99 percent[1]	Until April 6, 2026.
		ii. Continuously reduce EtO emissions by 99.8 percent [2] [3]	No later than April 6, 2026.
	c. Facility EtO use is at least 30 tpy	i. Continuously reduce EtO emissions by 99.99 percent [2] [3]	No later than April 6, 2026.
	d. Facility EtO use is at least 10 tpy but less than 30 tpy	i. Continuously reduce EtO emissions by 99.9 percent [2] [3]	No later than April 6, 2026.
	e. Facility EtO use is less than 1 tpy	i. Continuously reduce EtO emissions by 99 percent [2] [4]	No later than April 5, 2027.
2. New SCV	a. Initial startup is on or before April 5, 2024, and facility EtO use is at least 30 tpy	i. Continuously reduce EtO emissions by 99.99 percent [2] [5]	No later than April 5, 2024.
	b. Initial startup is on or before April 5, 2024, and facility EtO use is at least 10 tpy but less than 30 tpy	i. Continuously reduce EtO emissions by 99.9 percent [2] [5]	No later than April 5, 2024.
	c. Initial startup is on or before April 5, 2024, and facility EtO use is at least 1 tpy but less than 10 tpy	i. Continuously reduce EtO emissions by 99.8 percent [2] [5]	No later than April 5, 2024.
	d. Initial startup is on or before April 5, 2024, and facility EtO use is less than 1 tpy	i. Continuously reduce EtO emissions by 99 percent [2] [6]	No later than April 5, 2024.
	e. Initial startup is after April 5, 2024, and facility EtO use is at least 30 tpy	i. Continuously reduce EtO emissions by 99.99 percent [2] [5]	Upon startup of the source.
	f. Initial startup is after April 5, 2024, and facility EtO use is at least 10 tpy but less than 30 tpy	i. Continuously reduce EtO emissions by 99.9 percent [2] [5]	Upon startup of the source.
	g. Initial startup is after April 5, 2024, and facility EtO use is at least 1 tpy but less than 10 tpy	i. Continuously reduce EtO emissions by 99.8 percent [2] [5]	Upon startup of the source.
	h. Initial startup is after April 5, 2024, and facility EtO use is less than 1 tpy	i. Continuously reduce EtO emissions by 99 percent [2]	Upon startup of the source.

For each . . .	For which . . .	You must . . .	You must comply with the standard . . .
		[6]	

[1] The standard applies if the facility has met or exceeded the specified EtO use within any consecutive 12-month period after December 6, 1996.

[2] If using EtO CEMS to determine compliance, this standard is based on the previous 30 operating days of data.

[3] The standard applies if the facility has met or exceeded the specified EtO use within any consecutive 12-month period after April 7, 2025.

[4] The standard applies if the facility has used less than 1 tpy of EtO within all consecutive 12-month periods after April 6, 2026.

[5] The standard applies if the facility is expected to meet or exceed the specified EtO use within one year after startup. Afterwards, the standard applies if the facility has met or exceeded the specified EtO use within any consecutive 12-month period after startup.

[6] The standard applies if the facility is not expected to meet or exceed 1 tpy of EtO use within one year after startup. Afterwards, the standard applies if the facility has used less than 1 tpy of EtO within all consecutive 12-month periods after startup.

Table 2 to Subpart O of Part 63—Standards for ARVs

As required in § 63.362(d), for each ARV, you must meet the applicable standard in the following table:

For each . . .	For which . . .	You must . . .	You must comply with the standard . . .
1. Existing ARV	a. Facility EtO use is at least 10 tpy	i. Continuously reduce EtO emissions by 99 percent[1]	Until April 6, 2026.
	b. Facility EtO use is at least 30 tpy	i. Continuously reduce EtO emissions by 99.9 percent [2,3]	No later than April 6, 2026.
	c. Facility EtO use is at least 10 tpy but less than 30 tpy	i. Continuously reduce EtO emissions by 99.6 percent [2,3]	No later than April 6, 2026.
	d. Facility EtO use is less than 10 tpy	i. Continuously reduce EtO emissions by 99 percent [2,4]	No later than April 5, 2027.
2. New ARV	a. Initial startup is on or before April 5, 2024, and facility EtO use is at least 10 tpy	i. Continuously reduce EtO emissions by 99.9 percent [2,5]	No later than April 5, 2024.

For each . . .	For which . . .	You must . . .	You must comply with the standard . . .
	b. Initial startup is on or before April 5, 2024, and facility EtO use is less than 10 tpy	i. Continuously reduce EtO emissions by 99 percent [2] [6]	No later than April 5, 2024.
	c. Initial startup is after April 5, 2024, and facility EtO use is at least 10 tpy	i. Continuously reduce EtO emissions by 99.9 percent [2] [5]	Upon startup of the source.
	d. Initial startup is after April 5, 2024, and facility EtO use is less than 10 tpy	i. Continuously reduce EtO emissions by 99 percent [2] [6]	Upon startup of the source.

[1] The standard applies if the facility has met or exceeded the specified EtO use within any consecutive 12-month period after December 6, 1996.

[2] If using CEMS to determine compliance, this standard is based on a rolling 30-operating day average.

[3] The standard applies if the facility has met or exceeded the specified EtO use within any consecutive 12-month period after April 7, 2025.

[4] The standard applies if the facility has used less than 10 tpy of EtO within all consecutive 12-month periods after April 6, 2026.

[5] The standard applies if the facility is expected to meet or exceed the specified EtO use within one year after startup. Afterwards, the standard applies if the facility has met or exceeded the specified EtO use within any consecutive 12-month period after startup.

[6] The standard applies if the facility is not expected to meet or exceed 10 tpy of EtO use within one year after startup. Afterwards, the standard applies if the facility has used less than 10 tpy of EtO within all consecutive 12-month periods after startup.

Table 3 to Subpart O of Part 63—Standards for CEVs

As required in § 63.362(e), for each CEV, you must meet the applicable standard in the following table:

For each . . .	For which . . .	You must . . .	You must comply with the standard . . .
1. Existing CEV at a major source facility	a. Not applicable	i. Continuously reduce EtO emissions by 99.94 percent[1]	No later than April 5, 2027.
2. Existing CEV at an area source facility	a. Facility EtO use is at least 60 tpy	i. Continuously reduce EtO emissions by 99.9 percent [1] [2]	No later than April 6, 2026.
	b. Facility EtO use is less than 60 tpy	i. Continuously reduce EtO emissions by 99	No later than April 5, 2027.

For each . . .	For which . . .	You must . . .	You must comply with the standard . . .
		percent [1] [3]	
3. New CEV at a major source facility	a. Initial startup is on or before April 5, 2024	i. Continuously reduce EtO emissions by 99.94 percent[1]	No later than April 5, 2024.
	b. Initial startup is after April 5, 2024	i. Continuously reduce EtO emissions by 99.94 percent[1]	Upon startup of the source.
4. New CEV at an area source facility	a. Initial startup is on or before April 5, 2024, and facility EtO use is at least 60 tpy	i. Continuously reduce EtO emissions by 99.9 percent [1] [4]	No later than April 5, 2024.
	b. Initial startup is on or before April 5, 2024, facility EtO use is less than 60 tpy	i. Continuously reduce EtO emissions by 99 percent [1] [5]	No later than April 5, 2024.
	c. Initial startup is after April 5, 2024, and facility EtO use is at least 60 tpy	i. Continuously reduce EtO emissions by 99.9 percent [1] [4]	Upon startup of the source.
	d. Initial startup is after April 5, 2024, facility EtO use is less than 60 tpy	i. Continuously reduce EtO emissions by 99 percent [1] [5]	Upon startup of the source.

[1] If using CEMS to determine compliance, this standard is based on a rolling 30-operating day average.

[2] The standard applies if the facility has met or exceeded the specified EtO use within any consecutive 12-month period after April 7, 2025.

[3] The standard applies if the facility has used less than 60 tpy of EtO within all consecutive 12-month periods after April 6, 2026.

[4] The standard applies if the facility is expected to meet or exceed the specified EtO use within one year after startup. Afterwards, the standard applies if the facility has met or exceeded the specified EtO use within any consecutive 12-month period after startup.

[5] The standard applies if the facility is not expected to meet or exceed 60 tpy of EtO use within one year after startup. Afterwards, the standard applies if the facility has used less than 60 tpy of EtO within all consecutive 12-month periods after startup.

Table 4 to Subpart O of Part 63—Standards for Group 1 Room Air Emissions

As required in § 63.362(f), for your collection of Group 1 room air emissions at each facility, you must meet the applicable standard in the following table:

For each . . .	For which . . .	You must . . .	You must comply with the requirement(s) . . .
1. Existing collection of Group 1 room air emissions at a major source facility	a. Not applicable	i. Operate all areas of the facility that contain Group 1 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system. Also, ii. Continuously reduce EtO emissions by 97 percent[1]	No later than April 5, 2027.
2. Existing collection of Group 1 room air emissions at an area source facility	a. Facility EtO use is at least 40 tpy	i. Operate all areas of the facility that contain Group 1 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system.[2] Also, ii. Continuously reduce EtO emissions by 98 percent[12]	No later than April 6, 2026.
	b. Facility EtO use is less than 40 tpy	i. Operate all areas of the facility that contain Group 1 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system. Also, ii. Continuously reduce EtO emissions by 80 percent[13]	No later than April 5, 2027.
3. New collection of Group 1 room air emissions at a major source facility	a. Initial startup is on or before April 5, 2024	i. Operate all areas of the facility that contain Group 1 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system. Also, ii. Continuously reduce EtO emissions by 97 percent[1]	No later than April 5, 2024.
	b. Initial startup is after April 5, 2024	i. Operate all areas of the facility that contain Group 1 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system. Also, ii. Continuously reduce EtO emissions by 97 percent[1]	Upon startup of the source.
4. New collection of Group 1 room air emissions at an	a. Initial startup is on or before April 5, 2024, and facility EtO	i. Operate all areas of the facility that contain Group 1 room air emissions with PTE, with all exhaust gas streams being	No later than April 5, 2024.

For each . . .	For which . . .	You must . . .	You must comply with the requirement(s) . . .
area source facility	use is at least 40 tpy	captured and routed to a control system.[4] Also, ii. Continuously reduce EtO emissions by 98 percent[14]	
	b. Initial startup is on or before April 5, 2024, and facility EtO use is less than 40 tpy	i. Operate all areas of the facility that contain Group 1 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system.[5] Also, ii. Continuously reduce EtO emissions by 80 percent[15]	No later than April 5, 2024.
	c. Initial startup is after April 5, 2024, and facility EtO use is at least 40 tpy	i. Operate all areas of the facility that contain Group 1 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system.[4] Also, ii. Continuously reduce EtO emissions by 98 percent[14]	Upon startup of the source.
	d. Initial startup is after April 5, 2024, and facility EtO use is less than 40 tpy	i. Operate all areas of the facility that contain Group 1 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system.[5] Also, ii. Continuously reduce EtO emissions by 80 percent[15]	Upon startup of the source.

[1] If using CEMS to determine compliance, this standard is based on a rolling 30-operating day average.

[2] The standard applies if the facility has met or exceeded the specified EtO use within any consecutive 12-month period after April 7, 2025.

[3] The standard applies if the facility has used less than 40 tpy of EtO within all consecutive 12-month periods after April 6, 2026.

[4] The standard applies if the facility is expected to meet or exceed the specified EtO use within one year after startup. Afterwards, the standard applies if the facility has met or exceeded the specified EtO use within any consecutive 12-month period after startup.

[5] The standard applies if the facility is not expected to meet or exceed 40 tpy of EtO use within one year after startup. Afterwards, the standard applies if the facility has used less than 40 tpy of EtO within all consecutive 12-month periods after startup.

Table 5 to Subpart O of Part 63—Standards for Group 2 Room Air Emissions

As required in § 63.362(g), for your collection of Group 2 room air emissions, you must meet the applicable standard in the following table:

For each . . .	For which . . .	You must . . .	You must comply with the requirement(s) . . .
1. Existing collection of Group 2 room air emissions at a major source facility	a. Not applicable	i. Operate all areas of the facility that contain Group 2 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system. Also, ii. Continuously reduce EtO emissions by 86 percent[1]	No later than April 5, 2027.
2. Existing collection of Group 2 room air emissions at an area source facility	a. Facility EtO use is at least 20 tpy	i. Operate all areas of the facility that contain Group 2 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system.[2] Also, ii. Continuously reduce EtO emissions by 98 percent[12]	No later than April 6, 2026.
	b. Facility EtO use is at least 4 tpy but less than 20 tpy	i. Operate all areas of the facility that contain Group 2 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system.[2] Also, ii. Continuously reduce EtO emissions by 80 percent[12]	No later than April 6, 2026.
	c. Facility EtO use is less than 4 tpy	Lower the EtO concentration within each sterilization chamber to 1 ppm before the chamber can be opened[3]	No later than April 5, 2027.
3. New collection of Group 2 room air emissions at a major source facility	a. Initial startup is on or before April 5, 2024	i. Operate all areas of the facility that contain Group 2 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system. Also, ii. Continuously reduce EtO emissions by 86 percent[1]	No later than April 5, 2024.
	b. Initial startup is after April 5, 2024	i. Operate all areas of the facility that contain Group 2 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system. Also, ii. Continuously reduce EtO emissions by 86 percent[1]	Upon startup of the source.

For each . . .	For which . . .	You must . . .	You must comply with the requirement(s) . . .
4. New collection of Group 2 room air emissions at an area source facility	a. Initial startup is on or before April 5, 2024, and facility EtO use is at least 20 tpy	i. Operate all areas of the facility that contain Group 2 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system.[5] Also, ii. Continuously reduce EtO emissions by 98 percent[15]	No later than April 5, 2024.
	b. Initial startup is on or before April 5, 2024, and facility EtO use is less than 20 tpy	i. Operate all areas of the facility that contain Group 2 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system.[6] Also, ii. Continuously reduce EtO emissions by 80 percent[16]	No later than April 5, 2024.
	c. Initial startup is after April 5, 2024, and facility EtO use is at least 20 tpy	i. Operate all areas of the facility that contain Group 2 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system.[5] Also, ii. Continuously reduce EtO emissions by 98 percent[15]	Upon startup of the source.
	d. Initial startup is after April 5, 2024, and facility EtO use is less than 20 tpy	i. Operate all areas of the facility that contain Group 2 room air emissions with PTE, with all exhaust gas streams being captured and routed to a control system.[6] Also, ii. Continuously reduce EtO emissions by 80 percent[16]	Upon startup of the source.

[1] This standard is based on a rolling 30-operating day average.

[2] The standard applies if the facility has met or exceeded the specified EtO use within any consecutive 12-month period after April 7, 2025.

[3] The standard applies if the facility has used less than 4 tpy of EtO within all consecutive 12-month periods after April 6, 2026.

[4] The standard applies if the facility is expected to meet or exceed the specified EtO use within one year after startup. Afterwards, the standard applies if the facility has met or exceeded the specified EtO use within any consecutive 12-month period after startup.

[5] The standard applies if the facility is not expected to meet or exceed 20 tpy of EtO use within one year after startup. Afterwards, the standard applies if the facility has used less than 20 tpy of EtO within all consecutive 12-month periods after startup.

Table 6 to Subpart O of Part 63—Applicability of General Provisions to This Subpart

As specified in § 63.360, the parts of the General Provisions that apply to you are shown in the following table:

Citation	Subject	Applies to subpart O
§ 63.1(a)(1)	Applicability	Yes, additional terms defined in § 63.361; when overlap between subparts A and O occurs, subpart O takes precedence.
§ 63.1(a)(2)-(3)		Yes.
§ 63.1(a)(4)		Yes. Subpart O clarifies the applicability of each paragraph in subpart A to facilities subject to subpart O.
§ 63.1(a)(5)	[Reserved]	No.
§ 63.1(a)(6)-(8)		Yes.
§ 63.1(a)(9)	[Reserved]	
§ 63.1(a)(10)-(14)		Yes.
§ 63.1(b)(1)-(2)		Yes.
§ 63.1(b)(3)		No.
§ 63.1(c)(1)		No. Subpart O clarifies the applicability of each paragraph in subpart A to facilities subject to subpart O in this table.
§ 63.1(c)(2)		Yes.
§ 63.1(c)(3)	[Reserved]	No.
§ 63.1(c)(4)		Yes.
§ 63.1(c)(5)		No. § 63.360 specifies applicability.
§ 63.1(c)(6)		Yes.
§ 63.1(d)	[Reserved]	No.
§ 63.1(e)		Yes.
§ 63.2	Definitions	Yes, additional terms defined in § 63.361; when overlap between subparts A and O occurs, subpart O takes precedence.
§ 63.3	Units and abbreviations	Yes, other units used in subpart O are defined in the text of subpart O.
§ 63.4(a)(1)-(3)	Prohibited activities	Yes.
§ 63.5(a)	Construction/Reconstruction	No. § 63.366(b)(1) contains applicability requirements for constructed or reconstructed facilities.
§ 63.5(b)(1)		Yes.
§ 63.5(b)(2)	[Reserved]	

Citation	Subject	Applies to subpart O
§ 63.5(b)(3)		No. See § 63.366(b)(2).
§ 63.5(b)(4)-(6)		Yes.
§ 63.5(c)	[Reserved]	
§ 63.5(d)(1)-(2)		No. See § 63.366(b)(3).
§ 63.5(d)(3)-(4)		Yes.
§ 63.5(e)		Yes.
§ 63.5(f)(1)-(2)		No. See § 63.366(b)(4).
§ 63.6(a)	Applicability	Yes.
§ 63.6(b)-(c)		No. § 63.360(j) specifies compliance dates for facilities.
§ 63.6(d)	[Reserved]	
§ 63.6(e)(1)(i)		No.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(1)(iii)		Yes.
§ 63.6(e)(2)	[Reserved]	No.
§ 63.6(e)(3)	SSM Plan Requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(f)(2)(i)	Methods for Determining Compliance	Yes.
§ 63.6(f)(2)(ii)		No. § 63.363 specifies parameters for determining compliance.
§ 63.6(f)(2)(iii)-(iv)		Yes.
§ 63.6(f)(2)(v)		No.
§ 63.6(f)(3)		Yes.
§ 63.6(g)	Alternative Standard	Yes.
§ 63.6(h)	Compliance with opacity and visible emission standards	No. Subpart O does not contain any opacity or visible emission standards.
§ 63.6(i)(1)-(14), and (16)	Compliance Extension	Yes.
§ 63.6(j)	Presidential Compliance Exemption	Yes.
§ 63.7(a)	Applicability and Performance Test Dates	Yes.
§ 63.7(b)	Notification of Performance Test	Yes.
§ 63.7(c)	Quality Assurance/Test Plan	Yes.
§ 63.7(d)	Testing Facilities	Yes.
§ 63.7(e)(1)	SSM exemption	No.
§ 63.7(e)(2)-(4)	Conduct of Performance Tests	Yes. § 63.365 also contains test methods specific to facilities subject to the emissions standards.
§ 63.7(f)	Alternative Test Method	Yes.

Citation	Subject	Applies to subpart O
§ 63.7(g)	Performance Test Data Analysis	Yes, except this subpart specifies how and when the performance test and performance evaluation results are reported.
§ 63.7(h)	Waiver of Tests	Yes.
§ 63.8(a)(1)	Applicability of Monitoring Requirements	Yes.
§ 63.8(a)(2)	Performance Specifications	Yes.
§ 63.8(a)(3)	[Reserved]	No.
§ 63.8(a)(4)	Monitoring with Flares	Yes.
§ 63.8(b)(1)	Monitoring	Yes.
§ 63.8(b)(2)-(3)	Multiple Effluents and Multiple Monitoring Systems	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No.
§ 63.8(c)(1)(ii)		No. A startup, shutdown, and malfunction plan is not required for these standards.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(c)(2)-(3)		Yes.
§ 63.8(c)(4)-(5)		No. Frequency of monitoring measurements is provided in § 63.364; opacity monitors are not required for these standards.
§ 63.8(c)(6)		No. Performance specifications are contained in § 63.365.
§ 63.8(c)(7)(i)(A)-(B)		No. Performance specifications are contained in § 63.365.
§ 63.8(c)(7)(i)(C)		No. Opacity monitors are not required for these standards.
§ 63.8(c)(7)(ii)		No. Performance specifications are contained in § 63.365.
§ 63.8(c)(8)		No.
§ 63.8(d)(1)-(2)		Yes.
§ 63.8(d)(3)	Written procedures for CMS	No.
§ 63.8(e)(1)	CMS Performance Evaluation	Yes, but only applies for CEMS, except this subpart specifies how and when the performance evaluation results are reported.
§ 63.8(e)(2)		Yes.
§ 63.8(e)(3)		Yes.
§ 63.8(e)(4)		Yes.
§ 63.8(e)(5)(i)		Yes.
§ 63.8(e)(5)(ii)		No. Opacity monitors are not required for these standards.

Citation	Subject	Applies to subpart O
§ 63.8(f)(1)-(5)		Yes.
§ 63.8(f)(6)		No.
§ 63.8(g)(1)		Yes.
§ 63.8(g)(2)		No.
§ 63.8(g)(3)-(5)		Yes.
§ 63.9(a)	Notification requirements	Yes.
§ 63.9(b)(1)-(i)		Yes.
§ 63.9(b)(1)(ii)-(iii)	Initial Notifications	No. § 63.366(c)(1)(i) contains language for facilities that increase usage such that the source becomes subject to the emissions standards.
§ 63.9(b)(2)-(3)	Initial Notifications	Yes. § 63.366(c)(3) contains additional information to be included in the initial report for existing and new facilities.
§ 63.9(b)(4)-(5)	Initial Notifications	No. § 63.366(c)(1)(ii) and (iii) contains requirements for new or reconstructed facilities subject to the emissions standards.
§ 63.9(c)	Request for Compliance Extension	Yes.
§ 63.9(d)	Notification of Special Compliance Requirements for New Sources	No.
§ 63.9(e)	Notification of Performance Test	Yes.
§ 63.9(f)	Notification of VE/Opacity Test	No. Opacity monitors are not required for these standards.
§ 63.9(g)(1)	Additional Notifications When Using CMS	Yes.
§ 63.9(g)(2)-(3)	Additional Notifications When Using CMS	No. Opacity monitors and relative accuracy testing are not required for these standards.
§ 63.9(h)(1)-(3)	Notification of Compliance Status	Yes, except § 63.9(h)(5) does not apply because § 63.366(c)(2) instructs facilities to submit actual data.
§ 63.9(i)	Adjustment of Submittal Deadlines	Yes.
§ 63.9(j)	Change in previous information	Yes.
§ 63.9(k)	Electronic reporting procedures	Yes, as specified in § 63.9(j).
§ 63.10(a)	Recordkeeping/Reporting	Yes.
§ 63.10(b)(1)	Recordkeeping/Reporting	Yes.
§ 63.10(b)(2)(i)	Recordkeeping for startup and shutdown	No. See 63.367(f) for recordkeeping requirements.
§ 63.10(b)(2)(ii)	Recordkeeping for SSM and failures to meet standards	No. See 63.367(f) for recordkeeping requirements.
§ 63.10(b)(2)(iii)	Records related to maintenance of air pollution control equipment	Yes.

Citation	Subject	Applies to subpart O
§ 63.10(b)(2)(iv)-(v)	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(vi)	CMS Records	Yes.
§ 63.10(b)(2)(vii)-(ix)	Records	Yes.
§ 63.10(b)(2)(x)-(xi)	CMS Records	Yes.
§ 63.10(b)(2)(xii)	Records	Yes.
§ 63.10(b)(2)(xiii)	Records	Yes.
§ 63.10(b)(2)(xiv)	Records	Yes.
§ 63.10(b)(3)	Records	Yes.
§ 63.10(c)(1)-(14)	Records	Yes.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(1)	General Reporting Requirements	Yes.
§ 63.10(d)(2)	Report of Performance Test Results	No. This subpart specifies how and when the performance test results are reported.
§ 63.10(d)(3)	Reporting Opacity or VE Observations	No. Subpart O does not contain opacity or visible emissions standards.
§ 63.10(d)(4)	Progress Reports	Yes.
§ 63.10(d)(5)	SSM Reports	No. See § 63.366 for malfunction reporting requirements.
§ 63.10(e)(1)	Additional CEMS Reports	Yes.
§ 63.10(e)(2)(i)	Additional CMS Reports	Yes, except this subpart specifies how and when the performance evaluation results are reported.
§ 63.10(e)(2)(ii)	Additional COMS Reports	No. Opacity monitors are not required for these standards.
§ 63.10(e)(3)(i)-(iv)	Reports	Yes.
§ 63.10(e)(3)(v)	Excess Emissions Reports	No. § 63.366(b) and (c) specify contents and submittal dates for excess emissions and monitoring system performance reports.
§ 63.10(e)(3)(vi)-(viii)	Excess Emissions Report and Summary Report	Yes.
§ 63.10(e)(4)	Reporting COMS data	No. Opacity monitors are not required for these

Citation	Subject	Applies to subpart O
		standards.
§ 63.10(f)	Waiver for Recordkeeping/ Reporting	Yes.
§ 63.11	Control device requirements for flares and work practice requirements for equipment leaks	Yes.
§ 63.12	Delegation	Yes.
§ 63.13	Addresses	Yes.
§ 63.14	Incorporation by Reference	Yes.
§ 63.15	Availability of Information	Yes.

Appendix A to Subpart O of Part 63—Monitoring Provisions for EtO CEMS

1. Applicability

These monitoring provisions apply to the measurement of EtO emissions from commercial sterilization facilities, using CEMS. The CEMS must be capable of measuring EtO in lb/hr.

2. Monitoring of EtO Emissions

2.1 ***Monitoring System Installation Requirements.*** Install EtO CEMS and any additional monitoring systems needed to convert pollutant concentrations to lb/hr in accordance with § 63.365 and Performance Specification 19 (PS 19) of appendix B to part 60 of this chapter.

2.2 ***Primary and Backup Monitoring Systems.*** In the electronic monitoring plan described in section 10.1.1.2.1 of this appendix, you must designate a primary EtO CEMS. The primary EtO CEMS must be used to report hourly EtO concentration values when the system is able to provide quality-assured data, *i.e.,* when the system is “in control”. However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate backup monitoring systems, as follows:

2.2.1 ***Redundant Backup Systems.*** A redundant backup monitoring system is a separate EtO CEMS with its own probe, sample interface, and analyzer. A redundant backup system is one that is permanently installed at the unit or stack location and is kept on “hot standby” in case the primary monitoring system is unable to provide quality-assured data. A redundant backup system must be represented as a unique monitoring system in the electronic monitoring plan. Each redundant backup monitoring system must be certified according to the applicable provisions in section 3 of this appendix and must meet the applicable on-going QA requirements in section 5 of this appendix.

2.2.2 ***Non-redundant Backup Monitoring Systems.*** A non-redundant backup monitoring system is a separate EtO CEMS that has been certified at a particular unit or stack location but is not permanently installed at that location. Rather, the system is kept on “cold standby” and may be reinstalled in the event of a primary monitoring system outage. A nonredundant backup monitoring system must be represented as a unique monitoring system in the electronic monitoring plan. Non-redundant backup EtO CEMS must complete the same certification tests as the primary monitoring system, with one exception. The 7-day calibration error test is not required for a non-redundant backup EtO CEMS. Except as otherwise provided in section 2.2.4.4 of this appendix, a non-redundant backup monitoring system may only be used for 720 hours per year at a particular unit or stack location.

2.2.3 ***Temporary Like-kind Replacement Analyzers.*** When a primary EtO analyzer needs repair or maintenance, you may temporarily install a like-kind replacement analyzer, to minimize data loss. Except as otherwise provided in section 2.2.4.4 of this appendix, a temporary like-kind replacement analyzer may only be used for 720 hours per year at a particular unit or stack location. The analyzer must be represented as a component of the primary EtO CEMS and must be assigned a 3-character component ID number, beginning with the prefix "LK".

2.2.4 ***Quality Assurance Requirements for Non-redundant Backup Monitoring Systems and Temporary Like-kind Replacement Analyzers.*** To quality-assure the data from non-redundant backup EtO monitoring systems and temporary like-kind replacement EtO analyzers, the following provisions apply:

2.2.4.1 When a certified non-redundant backup EtO CEMS or a temporary like-kind replacement EtO analyzer is brought into service, a calibration error test and a linearity check must be performed and passed. A single point system integrity check is also required.

2.2.4.2 Each non-redundant backup EtO CEMS or temporary like-kind replacement EtO analyzer shall comply with all required daily, weekly, and quarterly quality-assurance test requirements in section 5 of this appendix, for as long as the system or analyzer remains in service.

2.2.4.3 For the routine, on-going quality-assurance of a non-redundant backup EtO monitoring system, a relative accuracy test audit (RATA) must be performed and passed at least once every 8 calendar quarters at the unit or stack location(s) where the system will be used.

2.2.4.4 To use a non-redundant backup EtO monitoring system or a temporary like-kind replacement analyzer for more than 720 hours per year at a particular unit or stack location, a RATA must first be performed and passed at that location.

2.3 ***Monitoring System Equipment, Supplies, Definitions, and General Operation.***

The following provisions apply:

2.3.1 PS 19, Sections 3.0, 6.0, and 11.0 of appendix B to part 60 of this chapter.

3. Initial Certification Procedures

The initial certification procedures for the EtO CEMS used to provide data under this subpart are as follows:

3.1 Your EtO CEMS must be certified according to PS 19, section(s) 13.

3.2 Any additional stack gas flow rate monitoring system(s) needed to express pollutant concentrations in lb/hr must be certified according to part 75 of this chapter.

4. Recertification Procedures

Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS that may significantly affect the ability of the system to accurately measure or record pollutant gas concentrations or stack gas flow rates, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: Replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. On-Going Quality Assurance Requirements

On-going QA test requirements for EtO CEMS must be implemented as follows:

5.1 The quality assurance/quality control procedures in Procedure 7 of appendix F to part 60 of this chapter shall apply.

5.2 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable ongoing QA test requirements of part 75 of this chapter.

5.2.1 ***Out-of-Control Periods.*** A EtO CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The EtO CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.2.2 ***Grace Periods.*** For the purposes of this appendix, a “grace period” is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.2.2.1 For the flow rate monitoring systems described in section 5.1 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.2.2.2 For the purposes of this appendix, if the deadline for a required gas audit or RATA of a EtO CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.2.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit; or

5.2.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.2.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.2.2.3.1 For the gas audit of an EtO CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit is required for that quarter.

5.2.2.3.2 For the RATA of an EtO CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.2.3 ***Conditional Data Validation.*** For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when nonredundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit shall be the same as for a linearity check (*i.e.,* 168 unit or stack operating hours).

5.3 ***Data Validation.***

5.3.1 ***Out-of-Control Periods.*** An EtO CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The EtO CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.3.2 ***Grace Periods.*** For the purposes of this appendix, a “grace period” is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.3.2.1 For the monitoring systems described in section 5.1 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.3.2.2 For the purposes of this appendix, if the deadline for a required gas audit/data accuracy assessment or RATA of an EtO CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.3.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit or other quarterly data accuracy assessment; or

5.3.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.3.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.3.2.3.1 For a gas audit or RATA of the monitoring systems described in sections 5.1 and 5.2 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.3.2.3.2 For the gas audit or other quarterly data accuracy assessment of an EtO CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit/data accuracy assessment is required for that quarter.

5.3.2.3.3 For the RATA of an EtO CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.3.3 ***Conditional Data Validation.*** For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, the conditional data validation provisions in § 75.20(b)(3)(ii) through (ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a quarterly gas audit or data accuracy assessment shall be the same as for a linearity check (*i.e.,* 168 unit or stack operating hours).

6. Missing Data Requirements

For the purposes of this appendix, the owner or operator of an affected unit shall not substitute for missing data from EtO CEMS. Any process operating hour for which quality-assured EtO concentration data are not obtained is counted as an hour of monitoring system downtime.

7. Bias Adjustment

Bias adjustment of hourly emissions data from an EtO CEMS is not required.

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the EtO CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.2 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

8.1 *General Requirements for EtO CEMS.*

8.1.1 ***Preventive Maintenance.*** Keep a written record of procedures needed to maintain the EtO CEMS in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

8.1.2 ***Recordkeeping and Reporting.*** Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

8.1.3 ***Maintenance Records.*** Keep a record of all testing, maintenance, or repair activities performed on any EtO CEMS in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: Date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded and a written explanation of the procedures used to make the adjustment(s) shall be kept.

8.2 ***Specific Requirements for EtO CEMS.*** The following requirements are specific to EtO CEMS:

8.2.1 Keep a written record of the procedures used for each type of QA test required for each EtO CEMS. Explain how the results of each type of QA test are calculated and evaluated.

8.2.2 Explain how each component of the EtO CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

9. Data Reduction and Calculations

9.1 Design and operate the EtO CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

9.2 Reduce the EtO concentration data to hourly averages in accordance with § 60.13(h)(2) of this chapter.

9.3 Convert each hourly average EtO concentration to an EtO mass emission rate (lb/hr) using an equation that has the general form of equation A-1 of this appendix:

$$E_{ho} = KC_hQ_h \qquad \text{(Eq. A-1)}$$

Where:

E_{ho} = EtO mass emission rate for the hour, lb/hr

K = Units conversion constant, 1.144E-10 lb/scf-ppbv,

Ch = Hourly average EtO concentration, ppbv,

Q_h = Stack gas volumetric flow rate for the hour, scfh.

(NOTE: Use unadjusted flow rate values; bias adjustment is not required.)

9.4 Use equation A-2 of this appendix to calculate the daily total EtO emissions. Report each daily total to the same precision as the most stringent standard that applies to any affected source exhausting to the emission stream (*e.g.,* if the emission stream includes contributions from an SCV and ARV subject to 99.99% and 99.9% emission reduction standards, respectively, report to four significant figures), expressed in scientific notation.

$$E_{day} = \sum_{h=1}^{24} (E_{ho} * 1\ hr) \qquad \text{Equation A-2}$$

Where:

E_{day} = Total daily EtO emissions, lb.

E_{ho} = Hourly EtO emission rate for unit or stack sampling hour “h” in the averaging period, from equation A-1 of this appendix, lb/hr.

9.5 Use equation A-3 of this appendix to calculate the 30-operating day rolling total EtO emissions. Report each 30-operating day rolling total to the same precision as the most stringent standard that applies to any affected source exhausting to the emission stream (*e.g.,* if the emission stream includes contributions from an SCV and ARV subject to 99.99% and 99.9% emission reduction standards, respectively, report to four significant figures), expressed in scientific notation.

$$E_{30day} = \sum_{i=1}^{30} E_{day,i} \qquad \text{Equation A-3}$$

Where:

E_{30day} = Total EtO emissions during the 30-operating day, lb.

$E_{day,i}$ = Total daily EtO emissions, in lbs, for each operating day *i* from equation A-2 of this appendix, lb.

$_i$ = Operating day index.

10. Recordkeeping Requirements

10.1 For each EtO CEMS installed at an affected source, and for any other monitoring system(s) needed to convert pollutant concentrations to units of the applicable emissions limit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.367. The file shall contain the information in paragraphs 10.1.1 through 10.1.8 of this section.

10.1.1 ***Monitoring Plan Records.*** For each affected source or group of sources monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the EtO CEMS and any other monitoring system(s) (*i.e.,* flow rate, diluent gas, or moisture systems) needed to convert pollutant concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall explain how the data derived from these systems ensure that all EtO emissions from the unit or stack are monitored and reported.

10.1.1.1 ***Updates.*** Whenever the owner or operator makes a replacement, modification, or change in a certified continuous EtO monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (*e.g.,* a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

10.1.1.2 ***Contents of the Monitoring Plan.*** For EtO CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under § 75.53(g) of this chapter. The electronic monitoring plan shall be evaluated using CEDRI.

10.1.1.2.1 ***Electronic.*** Record the unit or stack ID number(s); monitoring location(s); the EtO monitoring methodology used (*i.e.,* CEMS); EtO monitoring system information, including, but not limited to: unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; monitor span and range information (if applicable).

10.1.1.2.2 ***Hard Copy.*** Keep records of the following: schematics and/or blueprints showing the location of the monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations (if applicable); miscellaneous technical justifications.

10.1.2 ***EtO Emissions Records.*** For EtO CEMS, the owner or operator must record the following information for each unit or stack operating hour:

10.1.2.1 The date and hour;

10.1.2.2 Monitoring system and component identification codes, as provided in the electronic monitoring plan, for each hour in which the CEMS provides a quality-assured value of EtO concentration (as applicable);

10.1.2.3 The pollutant concentration, for each hour in which a quality-assured value is obtained. Record the data in parts per billion by volume (ppbv), with one leading non-zero digit and one decimal place, expressed in scientific notation. Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged.

10.1.2.4 A special code, indicating whether or not a quality-assured EtO concentration value is obtained for the hour. This code may be entered manually when a temporary like-kind replacement EtO analyzer is used for reporting; and

10.1.2.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

10.1.3 ***Stack Gas Volumetric Flow Rate Records.***

10.1.3.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required to demonstrate compliance with EtO emission standards.

10.1.3.2 Use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

10.1.4 ***EtO Emission Rate Records.*** Record the following information for each affected unit or common stack:

10.1.4.1 The date and hour;

10.1.4.2 The hourly EtO emissions rate (lb/hr), for each hour in which valid values of EtO concentration and stack gas volumetric flow rate are obtained for the hour. Report each emission rate to the same precision as the most stringent standard that applies to any affected source exhausting to the emission stream (*e.g.,* if the emission stream includes contributions from an SCV and ARV subject to 99.99% and 99.9% emission reduction standards, respectively, report to four significant figures), expressed in scientific notation. Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged;

10.1.4.4 A code indicating that the EtO emission rate was not calculated for the hour, if valid data for EtO concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for stack gas flow rate are not considered to be valid data.

10.1.5 ***Certification and Quality Assurance Test Records.*** For the EtO CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.5.1 EtO CEMS.

10.1.5.1.1 For each required 7-day and daily calibration drift (CD) test or daily calibration error test (including daily calibration transfer standard tests) of the EtO CEMS, record the test date(s) and time(s), reference gas value(s), monitor response(s), and calculated calibration drift or calibration error value(s). If you use the dynamic spiking option for the mid-level calibration drift check under PS 19, you must also record the measured concentration of the native EtO in the flue gas before and after the spike and the spiked gas dilution factor.

10.1.5.1.2 or each required RATA of an EtO CEMS, record the beginning and ending date and time of each test run, the reference method(s) used, and the reference method and EtO CEMS run values. Keep records of stratification tests performed (if any), all of the raw field data, relevant process operating data, and all of the calculations used to determine the relative accuracy.

10.1.5.1.3 For each required measurement error (ME) test of an EtO monitor, record the date and time of each gas injection, the reference gas concentration (low, mid, or high) and the monitor response for each of the three injections at each of the three levels. Also record the average monitor response and the ME at each gas level and the related calculations.

10.1.5.1.4 For each required level of detection (LOD) test of an EtO monitor performed in a controlled environment, record the test date, the concentrations of the reference gas and interference gases, the results of the seven (or more) consecutive measurements of EtO, the standard deviation, and the LOD value. For each required LOD test performed in the field, record the test date, the three measurements of the native source EtO concentration, the results of the three independent standard addition (SA) measurements known as standard addition response (SAR), the effective spike addition gas concentration, the resulting standard addition detection level (SADL) value and all related calculations. For extractive CEMS performing the SA using dynamic spiking, you must record the spiked gas dilution factor.

10.1.5.1.5 For each required ME/level of detection response time test of an EtO monitor, record the test date, the native EtO concentration of the flue gas, the reference gas value, the stable reference gas readings, the upscale/downscale start and end times, and the results of the upscale and downscale stages of the test.

10.1.5.1.6 For each required interference test of an EtO monitor, record (or obtain from the analyzer manufacturer records of): The date of the test; the gas volume/rate, temperature, and pressure used to conduct the test; the EtO concentration of the reference gas used; the concentrations of the interference test gases; the baseline EtO responses for each interferent combination spiked; and the total percent interference as a function of span or EtO concentration.

10.1.5.1.7 For each quarterly relative accuracy audit (RAA) of an EtO monitor, record the beginning and ending date and time of each test run, the reference method used, the EtO concentrations measured by the reference method and CEMS for each test run, the average concentrations measured by the reference method and the CEMS, and the calculated relative accuracy. Keep records of the raw field data, relevant process operating data, and the calculations used to determine the relative accuracy.

10.1.5.1.8 For each quarterly cylinder gas audit (CGA) of an EtO monitor, record the date and time of each injection, and the reference gas concentration (zero, mid, or high) and the monitor response for each injection. Also record the average monitor response and the calculated ME at each gas level.

10.1.5.1.9 For each quarterly dynamic spiking audit (DSA) of an EtO monitor, record the date and time of the zero gas injection and each spike injection, the results of the zero gas injection, the gas concentrations (mid and high) and the dilution factors and the monitor response for each of the six upscale injections as well as the corresponding native EtO concentrations measured before and after each injection. Also record the average dynamic spiking error for each of the upscale gases, the calculated average DSA Accuracy at each upscale gas concentration, and all calculations leading to the DSA Accuracy.

10.1.5.2 ***Additional Monitoring Systems.*** For the stack gas flow rate monitoring systems described in section 3.2 of this appendix, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59(a) of this chapter.

11. Reporting Requirements

11.1 ***General Reporting Provisions.*** The owner or operator shall comply with the following requirements for reporting EtO emissions from each affected unit (or group of units monitored at a common stack):

11.1.1 Notifications, in accordance with paragraph 11.2 of this section;

11.1.2 Monitoring plan reporting, in accordance with paragraph 11.3 of this section;

11.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 11.4 of this section; and

11.1.4 Electronic quarterly report submittals, in accordance with paragraph 11.5 of this section.

11.2 ***Notifications.*** The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) in accordance with § 63.366.

11.3 ***Monitoring Plan Reporting.*** For each affected unit (or group of units monitored at a common stack) using EtO CEMS, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

11.3.1 For a sterilization facility that begins reporting hourly EtO concentrations with a previously certified CEMS, submit the monitoring plan information in section 10.1.1.2 of this appendix prior to or concurrent with the first required quarterly emissions report. For a new sterilization facility, submit the information in section 10.1.1.2 of this appendix at least 21 days prior to the start of initial certification testing of the CEMS. Also submit the monitoring plan information in § 75.53(g) of this chapter pertaining to any required flow rate monitoring systems within the applicable timeframe specified in this section, if the required records are not already in place.

11.3.2 Update the monitoring plan when required, as provided in paragraph 10.1.1.1 of this appendix. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

11.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using CEDRI. Hard copy portions of the monitoring plan shall be kept on record according to section 10.1 of this appendix.

11.4 ***Certification, Recertification, and Quality-Assurance Test Reporting Requirements.*** Use CEDRI to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically. Submit the test results concurrent with the quarterly electronic emissions report. However, for RATAs of the EtO monitor, if this is not possible, you have up to 60 days after the test completion date to submit the test results; in this case, you may claim provisional status for the emissions data affected by the test, starting from the date and hour in which the test was completed and continuing until the date and hour in which the test results are submitted. If the test is successful, the status of the data in that time period changes from provisional to quality-assured, and no further action is required. However, if the test is unsuccessful, the provisional data must be invalidated and resubmission of the affected emission report(s) is required.

11.4.1 For each daily CD (or calibration error) assessment (including daily calibration transfer standard tests), and for each seven-day calibration drift (CD) test of an EtO monitor, report:

11.4.1.1 Facility ID information;

11.4.1.2 The monitoring component ID;

11.4.1.3 The instrument span and span scale;

11.4.1.4 For each gas injection, the date and time, the calibration gas level (zero or high-level), the reference gas value (ppbv), and the monitor response (ppbv);

11.4.1.5 A flag to indicate whether dynamic spiking was used for the high-level value;

11.4.1.6 Calibration drift (percent of span or reference gas, as applicable);

11.4.1.7 When using the dynamic spiking option, the measured concentration of native EtO before and after each mid-level spike and the spiked gas dilution factor; and

11.4.1.8 Reason for test.

11.4.2 For each RATA of an EtO CEMS, report:

11.4.2.1 Facility ID information;

11.4.2.2 Monitoring system ID number;

11.4.2.3 Type of test (*i.e.,* initial or annual RATA);

11.4.2.4 Reason for test;

11.4.2.5 The reference method used;

11.4.2.6 Starting and ending date and time for each test run;

11.4.2.7 Units of measure;

11.4.2.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.2.9 Flags to indicate which test runs were used in the calculations;

11.4.2.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.2.11 Standard deviation, using equation 7 in section 12.6 of PS 19 in appendix B to part 60 of this chapter;

11.4.2.12 Confidence coefficient, using equation 8 in section 12.6 of PS 19 in appendix B to part 60 of this chapter;

11.4.2.13 t-value; and

11.4.2.14 Relative accuracy calculated using equation 11 in section 12.6 of PS 19 in appendix B to part 60 of this chapter.

11.4.3 For each measurement error (ME) test of an EtO monitor, report:

11.4.3.1 Facility ID information;

11.4.3.2 Monitoring component ID;

11.4.3.3 Instrument span and span scale;

11.4.3.4 For each gas injection, the date and time, the calibration gas level (zero, low, mid, or high), the reference gas value in ppbv and the monitor response.

11.4.3.5 For extractive CEMS, the mean reference value and mean of measured values at each reference gas level (ppbv).

11.4.3.6 ME at each reference gas level; and

11.4.3.7 Reason for test.

11.4.4 For each interference test of an EtO monitoring system, report:

11.4.4.1 Facility ID information;

11.4.4.2 Date of test;

11.4.4.3 Monitoring system ID;

11.4.4.4 Results of the test (pass or fail);

11.4.4.5 Reason for test; and

11.4.4.6 A flag to indicate whether the test was performed: On this particular monitoring system; on one of multiple systems of the same type; or by the manufacturer on a system with components of the same make and model(s) as this system.

11.4.5 For each LOD test of an EtO monitor, report:

11.4.5.1 Facility ID information;

11.4.5.2 Date of test;

11.4.5.3 Reason for test;

11.4.5.4 Monitoring system ID;

11.4.5.5 A code to indicate whether the test was done in a controlled environment or in the field;

11.4.5.6 EtO reference gas concentration;

11.4.5.7 EtO responses with interference gas (seven repetitions);

11.4.5.8 Standard deviation of EtO responses;

11.4.5.9 Effective spike addition gas concentrations;

11.4.5.10 EtO concentration measured without spike;

11.4.5.11 EtO concentration measured with spike;

11.4.5.12 Dilution factor for spike;

11.4.5.13 The controlled environment LOD value (ppbv or ppbv-meters);

11.4.5.14 The field determined standard addition detection level (SADL in ppbv or ppbv-meters); and

11.4.5.15 Result of LOD/SADL test (pass/fail).

11.4.6 For each ME or LOD response time test of an EtO monitor, report:

11.4.6.1 Facility ID information;

11.4.6.2 Date of test;

11.4.6.3 Monitoring component ID;

11.4.6.4 The higher of the upscale or downscale tests, in minutes; and

11.4.6.5 Reason for test.

11.4.7 For each quarterly RAA of an EtO monitor, report:

11.4.7.1 Facility ID information;

11.4.7.2 Monitoring system ID;

11.4.7.3 Begin and end time of each test run;

11.4.7.4 The reference method used;

11.4.7.5 The reference method and CEMS values for each test run, including the units of measure;

11.4.7.6 The mean reference method and CEMS values for the three test runs;

11.4.7.7 The calculated relative accuracy, percent; and

11.4.7.8 Reason for test.

11.4.8 For each quarterly cylinder gas audit of an EtO monitor, report:

11.4.8.1 Facility ID information;

11.4.8.2 Monitoring component ID;

11.4.8.3 Instrument span and span scale;

11.4.8.4 For each gas injection, the date and time, the reference gas level (zero, mid, or high), the reference gas value in ppbv, and the monitor response.

11.4.8.5 For extractive CEMS, the mean reference gas value and mean monitor response at each reference gas level (ppbv).

11.4.8.6 ME at each reference gas level; and

11.4.8.7 Reason for test.

11.4.9 For each quarterly DSA of an EtO monitor, report:

11.4.9.1 Facility ID information;

11.4.9.2 Monitoring component ID;

11.4.9.3 Instrument span and span scale;

11.4.9.4 For the zero gas injection, the date and time, and the monitor response (Note: The zero gas injection from a calibration drift check performed on the same day as the upscale spikes may be used for this purpose.);

11.4.9.5 Zero spike error;

11.4.9.6 For the upscale gas spiking, the date and time of each spike, the reference gas level (mid- or high-), the reference gas value (ppbv), the dilution factor, the native EtO concentrations before and after each spike, and the monitor response for each gas spike;

11.4.9.7 Upscale spike error;

11.4.9.8 DSA at the zero level and at each upscale gas level; and

11.4.9.9 Reason for test.

11.4.10 ***Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.*** For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.8.2 of this appendix.

11.5 ***Quarterly Reports.***

11.5.1 The owner or operator of any affected unit shall use CEDRI to submit electronic quarterly reports to the Administrator in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack). If the certified EtO CEMS is used for the initial compliance demonstration, EtO emissions reporting shall begin with the first operating hour of the 30-operating day compliance demonstration period. Otherwise, EtO emissions reporting shall begin with the first operating hour after successfully completing all required certification tests of the CEMS.

11.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

11.5.3 Each electronic quarterly report shall include the following information:

11.5.3.1 The date of report generation;

11.5.3.2 Facility identification information;

11.5.3.3 The information in sections 10.1.2 through 10.1.4 of this appendix, as applicable to the type(s) of monitoring system(s) used to measure the pollutant concentrations and other necessary parameters.

11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests) of the EtO monitor as described in section 10.1.8.1.1 of this appendix; and

11.5.3.5 If applicable, the results of all daily flow monitor interference checks, in accordance with section 10.1.8.2 of this appendix.

11.5.4 ***Compliance Certification.*** Based on reasonable inquiry of those persons with primary responsibility for ensuring that all EtO emissions from the affected unit(s) have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2018–0794; FRL–6716.3–02–OAR]

RIN 2060–AV53

National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes amendments to the national emission standards for hazardous air pollutants (NESHAP) for the Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs) source category. These final amendments are the result of the EPA's review of the 2020 Residual Risk and Technology Review (RTR). The changes, which were proposed under the technology review in April 2023, include amending the filterable particulate matter (fPM) surrogate emission standard for non-mercury metal hazardous air pollutants (HAP) for existing coal-fired EGUs, the fPM emission standard compliance demonstration requirements, and the mercury (Hg) emission standard for lignite-fired EGUs. Additionally, the EPA is finalizing a change to the definition of ''startup.'' The EPA did not propose, and is not finalizing, any changes to the 2020 Residual Risk Review.

DATES: This final rule is effective on July 8, 2024. The incorporation by reference of certain material listed in the rule was approved by the Director of the Federal Register as of April 16, 2012.

ADDRESSES: The U.S. Environmental Protection Agency (EPA) has established a docket for this action under Docket ID No. EPA–HQ–OAR–2018–0794. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *https://www.regulations.gov,* or in hard copy at the EPA Docket Center, WJC West Building, Room Number 3334, 1301 Constitution Ave. NW, Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action contact Sarah Benish, Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, P.O. Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5620; and email address: *benish.sarah@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

APH	air preheater
Btu	British Thermal Units
CAA	Clean Air Act
CEMS	continuous emission monitoring system
EGU	electric utility steam generating unit
EIA	Energy Information Administration
ESP	electrostatic precipitator
FF	fabric filter
FGD	flue gas desulfurization
fPM	filterable particulate matter
GWh	gigawatt-hour
HAP	hazardous air pollutant(s)
HCl	hydrogen chloride
HF	hydrogen fluoride
Hg	mercury
Hg^0	elemental Hg vapor
Hg^{2+}	divalent Hg
$HgCl_2$	mercuric chloride
Hg_p	particulate bound Hg
HQ	hazard quotient
ICR	Information Collection Request
IGCC	integrated gasification combined cycle
IPM	Integrated Planning Model
IRA	Inflation Reduction Act
lb	pounds
LEE	low emitting EGU
MACT	maximum achievable control technology
MATS	Mercury and Air Toxics Standards
MMacf	million actual cubic feet
MMBtu	million British thermal units of heat input
MW	megawatt
NAICS	North American Industry Classification System
NESHAP	national emission standards for hazardous air pollutants
NO_X	nitrogen oxides
NRECA	National Rural Electric Cooperative Association
OMB	Office of Management and Budget
PM	particulate matter
$PM_{2.5}$	fine particulate matter
PM CEMS	particulate matter continuous emission monitoring systems
REL	reference exposure level
RFA	Regulatory Flexibility Act
RIA	Regulatory Impact Analysis
RIN	Regulatory Information Number
RTR	residual risk and technology review
SC–CO_2	social cost of carbon
SO_2	sulfur dioxide
TBtu	trillion British thermal units of heat input
tpy	tons per year
UMRA	Unfunded Mandates Reform Act
WebFIRE	Web Factor Information Retrieval System

Background information. On April 24, 2023, the EPA proposed revisions to the Coal- and Oil-Fired EGU NESHAP based on our review of the 2020 RTR. In this action, we are finalizing revisions to the rule, commonly known as the Mercury and Air Toxics Standards (MATS). We summarize some of the more significant comments regarding the proposed rule that were received during the public comment period and provide our responses in this preamble. A summary of all other public comments on the proposal and the EPA's responses to those comments is available in *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review Proposed Rule Response to Comments,* Docket ID No. EPA–HQ–OAR–2018–0794. A ''track changes'' version of the regulatory language that incorporates the changes in this action is available in the docket.

Organization of this document. The information in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Background and Purpose of the Regulatory Action

Exposure to hazardous air pollutants (''HAP,'' sometimes known as toxic air pollution, including Hg, chromium, arsenic, and lead) can cause a range of adverse health effects including harming people's central nervous system; damage to their kidneys; and cancer. These adverse effects can be particularly acute for communities living near sources of HAP. Recognizing the dangers posed by HAP, Congress enacted Clean Air Act (CAA) section 112. Under CAA section 112, the EPA is required to set standards based on maximum achievable control technology (known as ''MACT'' standards) for major sources[1] of HAP that ''require the maximum degree of reduction in emissions of the hazardous air pollutants . . . (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impacts and energy requirements, determines is achievable.'' 42 U.S.C. 7412(d)(2). The EPA is further required to ''review, and revise'' those standards every 8 years ''as necessary (taking into account developments in practices, processes, and control technologies).'' *Id.* 7412(d)(6).

On January 20, 2021, President Biden signed Executive Order 13990, ''Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis'' (86 FR 7037; January 25, 2021). The executive order, among other things, instructed the EPA to review the 2020 final rule titled *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil- Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review* (85 FR 31286; May 22, 2020) (2020 Final Action) and to consider publishing a notice of proposed rulemaking suspending, revising, or rescinding that action. The 2020 Final Action included two parts: (1) a finding that it is not appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112; and (2) the RTR for the 2012 MATS Final Rule.

The EPA reviewed both parts of the 2020 Final Action. The results of the EPA's review of the first part, finding it is appropriate and necessary to regulate EGUs under CAA section 112, were proposed on February 9, 2022 (87 FR 7624) (2022 Proposal) and finalized on March 6, 2023 (88 FR 13956). In the 2022 Proposal, the EPA also solicited information on the performance and cost of new or improved technologies that control HAP emissions, improved methods of operation, and risk-related information to further inform the EPA's review of the second part, the 2020 MATS RTR. The EPA proposed amendments to the RTR on April 24, 2023 (88 FR 24854) (2023 Proposal) and this action finalizes those amendments and presents the final results of the EPA's review of the MATS RTR.

2. Summary of Major Provisions of the Regulatory Action

Coal- and oil-fired EGUs remain one of the largest domestic emitters of Hg and many other HAP, including many of the non-Hg HAP metals—including lead, arsenic, chromium, nickel, and cadmium—and hydrogen chloride (HCl). Exposure to these HAP, at certain levels and duration, is associated with a variety of adverse health effects. In the 2012 MATS Final Rule, the EPA established numerical standards for Hg, non-Hg HAP metals, and acid gas HAP emissions from coal- and oil-fired EGUs. The EPA also established work practice standards for emissions of organic HAP. To address emissions of non-Hg HAP

---

[1] The term ''major source'' means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 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. 42 U.S.C. 7412(a)(1).

metals, the EPA established individual emission limits for each of the 10 non-Hg HAP metals[2] emitted from coal- and oil- fired EGUs. Alternatively, affected sources could meet an emission standard for ''total non-Hg HAP metals'' by summing the emission rates of each of the non-Hg HAP metals or meet a fPM emission standard as a surrogate for the non-Hg HAP metals. For existing coal-fired EGUs, almost every unit has chosen to demonstrate compliance with the non-Hg HAP metals surrogate fPM emission standard of 0.030 pounds (lb) of fPM per million British thermal units of heat input (lb/MMBtu).

Pursuant to CAA section 112(d)(6), the EPA reviewed developments in the costs of control technologies, and the effectiveness of those technologies, as well as the costs of meeting a fPM emission standard that is more stringent than 0.030 lb/MMBtu and the other statutory factors. Based on that review, the EPA is finalizing, as proposed, a revised non-Hg HAP metal surrogate fPM emission standard for all existing coal-fired EGUs of 0.010 lb/MMBtu. This strengthened standard will ensure that the entire fleet of coal-fired EGUs is performing at the fPM pollution control levels currently achieved by the vast majority of regulated units. The EPA further concludes that it is the lowest level currently compatible with the use of PM CEMS for demonstrating compliance.

Relatedly, the EPA is also finalizing a revision to the requirements for demonstrating compliance with the revised fPM emission standard. Currently, affected EGUs that do not qualify for the low emitting EGU (LEE) program for fPM[3] can demonstrate compliance with the fPM standard either by conducting quarterly performance testing (*i.e.,* quarterly stack testing) or by using particulate matter (PM) continuous emission monitoring systems (PM CEMS). PM CEMS confer significant benefits, including increased transparency regarding emissions performance for sources, regulators, and the surrounding communities; and real-time identification of when control technologies are not performing as expected, allowing for quicker repairs. After considering updated information on the costs for quarterly performance testing compared to the costs of PM CEMS and the measurement capabilities of PM CEMS, as well as the many benefits of using PM CEMS, the EPA is finalizing, as proposed, a requirement that all coal- and oil-fired EGUs demonstrate compliance with the revised fPM emission standard by using PM CEMS. As the EPA explained in the 2023 Proposal, by requiring facilities to use PM CEMS, the current compliance method for the LEE program becomes superfluous since LEE is an optional program in which stack testing occurs infrequently, and the revised fPM limit is below the current fPM LEE program limit. Therefore, the EPA is finalizing, as proposed, the removal of the fPM LEE program.

Based on comments received during the public comment period, the EPA is not removing, but instead revising the alternative emission limits for the individual non-Hg HAP metals such as lead, arsenic, chromium, nickel, and cadmium and for the total non-Hg HAP metals proportional to the finalized fPM emission limit of 0.010 lb/MMBtu.[4] Owners and operators of EGUs seeking to use these alternative standards must request and receive approval to use a HAP metal continuous monitoring system (CMS) as an alternative test method under 40 CFR 63.7(f).

The EPA is also finalizing, as proposed, a more protective Hg emission standard for existing lignite-fired EGUs, requiring that such lignite-fired EGUs meet the same Hg emission standard as EGUs firing other types of coal (*i.e.,* bituminous and subbituminous), which is 1.2 lb of Hg per trillion British thermal units of heat input (lb/TBtu) or an alternative output-based standard of 0.013 lb per gigawatt-hour (lb/GWh). Finally, the EPA is finalizing, as proposed, the removal of the second option for defining the startup period for MATS-affected EGUs.

The EPA did not propose and is not finalizing modifications to the HCl emission standard (nor the alternative sulfur dioxide (SO_2) emission standard), which serves as a surrogate for all acid gas HAP (HCl, hydrogen fluoride (HF), selenium dioxide (SeO_2)) for existing coal-fired EGUs. The EPA proposed to require PM CEMS for existing integrated gasification combined cycle (IGCC) EGUs but is not finalizing this requirement due to technical issues calibrating CEMS on these types of EGUs and the related fact that fPM emissions from IGCCs are very low.

In establishing the final standards, as discussed in detail in sections IV., V., VI., and VII. of this preamble, the EPA considered the statutory direction and factors laid out by Congress in CAA section 112. Separately, pursuant to Executive Order 12866 and Executive Order 14904, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review* (Ref. EPA–452/R–24–005), is available in the docket, and is briefly summarized in sections I.A.3. and IX. of this preamble.

3. Costs and Benefits

In accordance with Executive Order 12866 and 14094, the EPA prepared a Regulatory Impact Analysis (RIA). The RIA presents estimates of the emission, cost, and benefit impacts of this final rulemaking for the 2028 to 2037 period; those estimates are summarized in this section.

The power industry's compliance costs are represented in the RIA as the projected change in electric power generation costs between the baseline and final rule scenarios. The quantified emission estimates presented in the RIA include changes in pollutants directly covered by this rule, such as Hg and non-Hg HAP metals, and changes in other pollutants emitted from the power sector due to the compliance actions projected under this final rule. The cumulative projected national-level emissions reductions over the 2028 to 2037 period under the finalized requirements are presented in table 1. The supporting details for these estimates can be found in the RIA.

BILLING CODE 6560–50–P

---

[2] The ten non-Hg HAP metals are antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

[3] In order to qualify for fPM LEE status, an EGU must demonstrate that its fPM emission rate is below 50 percent of standard (or 0.015 lb/MMBtu) from quarterly stack tests for 3 consecutive years. Once a source achieves LEE status for fPM, the source must conduct stack testing every 3 years to demonstrate that its emission rate remains below 50 percent of the standard.

[4] The emission limits for the individual non-Hg HAP metals and the total non-Hg HAP metals have been reduced by two-thirds, consistent with the revision of the fPM emission limit from 0.030 lb/MMBtu to 0.010 lb/MMBtu.

Table 1. Cumulative Projected Emissions Reductions under the Final Rule, 2028 to 2037[a]

Pollutant	Emissions Reductions
Hg (pounds)	9,500
$PM_{2.5}$ (tons)	5,400
SO_2 (tons)	770
NO_x (tons)	220
CO_2 (thousand tons)	650
non-Hg HAP metals (tons)[b]	49

[a] Values rounded to two significant figures.

[b] The non-Hg HAP metals are antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

The EPA expects that emission reductions under the final rulemaking will result in reduced exposure to Hg and non-Hg HAP metals. The EPA also projects health benefits due to improvements in particulate matter with a diameter of 2.5 micrometers or less ($PM_{2.5}$) and ozone and climate benefits from reductions in carbon dioxide (CO_2) emissions. The EPA also anticipates benefits from the increased transparency to the public, the assurance that standards are being met continuously, and the accelerated identification of anomalous emissions due to requiring PM CEMS in this final rule.

The EPA estimates negative net monetized benefits of this rule (see table 2 below). However, the benefit estimates informing this result represent only a partial accounting of the potential benefits of this final rule. Several categories of human welfare and climate benefits are unmonetized and are thus not directly reflected in the quantified net benefit estimates (see section IX.B. in this preamble and section 4 of the RIA for more details). In particular, estimating the economic benefits of reduced exposure to HAP generally has proven difficult for a number of reasons: it is difficult to undertake epidemiologic studies that have sufficient power to quantify the risks associated with HAP exposures experienced by U.S. populations on a daily basis; data used to estimate exposures in critical microenvironments are limited; and there remains insufficient economic research to support valuation of HAP benefits made even more challenging by the wide array of HAP and possible HAP effects.[5] In addition, due to data limitations, the EPA is also unable to quantify potential emissions impacts or monetize potential benefits from continuous monitoring requirements.

The present value (PV) and equivalent annual value (EAV) of costs, benefits, and net benefits of this rulemaking over the 2028 to 2037 period in 2019 dollars are shown in table 2. In this table, results are presented using a 2 percent discount rate. Results under other discount rates and supporting details for the estimates can be found in the RIA.

---

[5] See section II.B.2. for discussion of the public health and environmental hazards associated with HAP emissions from coal- and oil-fired EGUs and discussion on the limitations to monetizing and quantifying benefits from HAP reductions. See also *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration and Affirmation of the Appropriate and Necessary Supplemental Finding,* 88 FR 13956, 13970–73 (March 6, 2023).

Table 2. Projected Benefits, Costs, and Net Benefits under the Final Rule, 2028 to 2037 (millions of 2019 dollars, discounted to 2023)[a]

	2% Discount Rate	
	PV	EAV
Ozone- and $PM_{2.5}$-related Health Benefits	300	33
Climate Benefits[b]	130	14
Compliance Costs	860	96
Net Benefits[c]	-440	-49
Non-Monetized Benefits	Benefits from reductions of about 900 to 1000 pounds of Hg annually	
	Benefits from reductions of about 4 to 7 tons of non-Hg HAP metals annually	
	Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS	

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

[b] Climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the SC-CO_2 (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate.

[c] Several categories of benefits remain unmonetized and are thus not reflected in the table.

BILLING CODE 6560–50–C

The EPA notes that analysis of such impacts is distinct from the determinations finalized in this action under CAA section 112, which are based on the statutory factors the EPA discusses in section II.A. and sections IV. through VII. below.

B. Does this action apply to me?

Regulated entities. The source category that is the subject of this action is coal- and oil-fired EGUs regulated by NESHAP under 40 CFR part 63, subpart UUUUU, commonly known as MATS. The North American Industry Classification System (NAICS) codes for the coal- and oil-fired EGU source category are 221112, 221122, and 921150. This list of NAICS codes is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by the final action for the source category listed. To determine whether your facility is affected, you should examine the applicability criteria in the appropriate NESHAP. If you have any questions regarding the applicability of any aspect of this NESHAP, please contact the appropriate person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section of this preamble.

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this final action will also be available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this final action at: *https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version and key technical documents at this same website.

Additional information is available on the RTR website at *https://www.epa.gov/stationary-sources-air-pollution/risk-and-technology-review-national-emissions-standards-hazardous.* This information includes an overview of the RTR program and links to project websites for the RTR source categories.

D. Judicial Review and Administrative Reconsideration

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit (the Court) by July 8, 2024. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that only an objection to a rule or procedure that was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. This section also provides a mechanism for the EPA to reconsider the rule if the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within the period for public comment or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule. Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, WJC South Building, 1200 Pennsylvania Ave., NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate

General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Background

A. What is the statutory authority for this action?

1. Statutory Language

The statutory authority for this action is provided by sections 112 and 301 of the CAA, as amended (42 U.S.C. 7401 *et seq.*). Section 112 of the CAA establishes a multi-stage regulatory process to develop standards for emissions of HAP from stationary sources. Generally, during the first stage, Congress directed the EPA to establish technology-based standards to ensure that all major sources control HAP emissions at the level achieved by the best-performing sources, referred to as the MACT. After the first stage, Congress directed the EPA to review those standards periodically to determine whether they should be strengthened. Within 8 years after promulgation of the standards, the EPA must evaluate the MACT standards to determine whether the emission standards should be revised to address any remaining risk associated with HAP emissions. This second stage is commonly referred to as the ''residual risk review.'' In addition, the CAA also requires the EPA to review standards set under CAA section 112 on an ongoing basis no less than every 8 years and revise the standards as necessary taking into account any ''developments in practices, processes, and control technologies.'' This review is commonly referred to as the ''technology review,'' and is the primary subject of this final rule. The discussion that follows identifies the most relevant statutory sections and briefly explains the contours of the methodology used to implement these statutory requirements.

In the first stage of the CAA section 112 standard-setting process, the EPA promulgates technology-based standards under CAA section 112(d) for categories of sources identified as emitting one or more of the HAP listed in CAA section 112(b). Sources of HAP emissions are either major sources or area sources, and CAA section 112 establishes different requirements for major source standards and area source standards. ''Major sources'' are those that emit or have the potential to emit 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of any combination of HAP. All other sources are ''area sources.'' For major sources, CAA section 112(d)(2) provides that the technology-based NESHAP must reflect ''*the maximum degree of reduction* in emissions of the [HAP] subject to this section (*including a prohibition on such emissions, where achievable*) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impacts and energy requirements, determines is achievable.'' (emphasis added). These standards are commonly referred to as MACT standards. CAA section 112(d)(3) establishes a minimum control level for MACT standards, known as the MACT ''floor.''[6] In certain instances, as provided in CAA section 112(h), the EPA may set work practice standards in lieu of numerical emission standards. The EPA must also consider control options that are more stringent than the floor. Standards more stringent than the floor are commonly referred to as ''beyond-the-floor'' standards. For area sources, CAA section 112(d)(5) allows the EPA to set standards based on generally available control technologies or management practices (GACT standards) in lieu of MACT standards.[7]

For categories of major sources and any area source categories subject to MACT standards, the next stage in standard-setting focuses on identifying and addressing any remaining (*i.e.,* ''residual'') risk pursuant to CAA section 112(f)(2). The residual risk review requires the EPA to update standards if needed to provide an ample margin of safety to protect public health.

Concurrent with that review, and then at least every 8 years thereafter, CAA section 112(d)(6) requires the EPA to review standards promulgated under CAA section 112 and revise them ''as necessary (taking into account developments in practices, processes, and control technologies).'' *See Portland Cement Ass'n* v. *EPA,* 665 F.3d 177, 189 (D.C. Cir. 2011) (''Though EPA must review and revise standards 'no less often than every eight years,' 42 U.S.C. 7412(d)(6), nothing prohibits EPA from reassessing its standards more often.''). In conducting this review, which we call the ''technology review,'' the EPA is not required to recalculate the MACT floors that were established in earlier rulemakings. *Natural Resources Defense Council (NRDC)* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008); *Association of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667 (D.C. Cir. 2013). The EPA may consider cost in deciding whether to revise the standards pursuant to CAA section 112(d)(6). *See e.g., Nat'l Ass'n for Surface Finishing,* v. *EPA,* 795 F.3d 1, 11 (D.C. Cir. 2015). The EPA is required to address regulatory gaps, such as missing MACT standards for listed air toxics known to be emitted from the source category. *Louisiana Environmental Action Network (LEAN)* v. *EPA,* 955 F.3d 1088 (D.C. Cir. 2020). The residual risk review and the technology review are distinct requirements and are both mandatory.

In this action, the EPA is finalizing amendments to the MACT standards based on two independent sources of authority: (1) its review of the 2020 Final Action's risk and technology review pursuant to the EPA's statutory authority under CAA section 112, and (2) the EPA's inherent authority to reconsider previous decisions and to revise, replace, or repeal a decision to the extent permitted by law and supported by a reasoned explanation. *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515 (2009); *see also Motor Vehicle Mfrs. Ass'n* v. *State Farm Mutual Auto. Ins. Co.,* 463 U.S. 29, 42 (1983).

2. Statutory Structure and Legislative History

In addition to the text of the specific subsections of CAA section 112 discussed above, the statutory structure and legislative history of CAA section 112 further support the EPA's authority to take this action. Throughout CAA section 112 and its legislative history, Congress made clear its intent to quickly secure large reductions in the volume of HAP emissions from stationary sources based on technological developments in control technologies because of its recognition of the hazards to public health and the environment that result from exposure to such emissions. CAA section 112 and its legislative history also reveal Congress's understanding that fully characterizing the risks posed by HAP emissions was exceedingly difficult. Thus, Congress purposefully replaced a regime that required the EPA to make an assessment of risk in the first instance, with one in which Congress determined risk existed and directed the EPA to make swift and substantial reductions based upon the most stringent standards technology could achieve.

Specifically, in 1990, Congress radically transformed section 112 of the CAA and its treatment of HAP through the Clean Air Act Amendments, by

---

[6] Specifically, for existing sources, the MACT ''floor'' shall not be less stringent than the average emission reduction achieved by the best performing 12 percent of existing sources. 42 U.S.C. 7412(d)(3). For new sources MACT shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source. *Id.*

[7] For categories of area sources subject to GACT standards, there is no requirement to address residual risk, but, similar to the major source categories, the technology review is required.

amending CAA section 112 to be a technology-driven standard setting provision as opposed to the risk-based one that Congress initially promulgated in the 1970 CAA. The legislative history of the 1990 Amendments indicates Congress's dissatisfaction with the EPA's slow pace addressing HAP under the 1970 CAA: ''In theory, [hazardous air pollutants] were to be stringently controlled under the existing Clean Air Act section 112. However, . . . only 7 of the hundreds of potentially hazardous air pollutants have been regulated by EPA since section 112 was enacted in 1970.'' H.R. Rep. No. 101–490, at 315 (1990); see also *id.* at 151 (noting that in 20 years, the EPA's establishment of standards for only seven HAP covered ''a small fraction of the many substances associated . . . with cancer, birth defects, neurological damage, or other serious health impacts.'').

In enacting the 1990 Amendments with respect to the control of HAP, Congress noted that ''[p]ollutants controlled under [section 112] tend to be less widespread than those regulated [under other sections of the CAA], but are often associated with more serious health impacts, such as cancer, neurological disorders, and reproductive dysfunctions.'' *Id.* at 315. In its substantial 1990 Amendments, Congress itself listed 189 HAP (CAA section 112(b)) and set forth a statutory structure that would ensure swift regulation of a significant majority of these HAP emissions from stationary sources. Specifically, after defining major and area sources and requiring the EPA to list all major sources and many area sources of the listed pollutants (CAA section 112(c)), the new CAA section 112 required the EPA to establish technology-based emission standards for listed source categories on a prompt schedule and to revisit those technology-based standards every 8 years on an ongoing basis (CAA section 112(d) (emission standards); CAA section 112(e) (schedule for standards and review)). The 1990 Amendments also obligated the EPA to conduct a one-time evaluation of the residual risk within 8 years of promulgation of technology-based standards. CAA section 112(f)(2).

In setting the standards, CAA section 112(d) requires the EPA to establish technology-based standards that achieve the ''maximum degree of reduction,'' ''including a prohibition on such emissions where achievable.'' CAA section 112(d)(2). Congress specified that the maximum degree of reduction must be at least as stringent as the average level of control achieved in practice by the best performing sources in the category or subcategory based on emissions data available to the EPA at the time of promulgation. This technology-based approach enabled the EPA to swiftly set standards for source categories without determining the risk or cost in each specific case, as the EPA had done prior to the 1990 Amendments. In other words, this approach to regulation quickly required that all major sources and many area sources of HAP meet an emission standard consistent with the top performers in each category, which had the effect of obtaining immediate reductions in the volume of HAP emissions from stationary sources. The statutory requirement that sources obtain levels of emission limitation that have actually been achieved by existing sources, instead of levels that could theoretically be achieved, inherently reflects a built-in cost consideration.[8]

Further, after determining the minimum stringency level of control, or MACT floor, CAA section 112(d)(2) directs the EPA to ''require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions, where achievable)'' that the EPA determines are achievable after considering the cost of achieving such standards and any non-air-quality health and environmental impacts and energy requirements of additional control. In doing so, the statute further specifies in CAA section 112(d)(2) that the EPA should consider requiring sources to apply measures that, among other things, ''reduce the volume of, or eliminate emissions of, such pollutants . . . '' (CAA section 112(d)(2)(A)), ''enclose systems or processes to eliminate emissions'' (CAA section 112(d)(2)(B)), and ''collect, capture, or treat such pollutants when released . . . '' (CAA section 112(d)(2)(C)). The 1990 Amendments also built in a regular review of new technologies and a one-time review of risks that remain after imposition of MACT standards. CAA section 112(d)(6) requires the EPA to evaluate every NESHAP no less often than every 8 years to determine whether additional control is necessary after taking into consideration ''developments in practices, processes, and control technologies,'' separate from its obligation to review residual risk. CAA section 112(f) requires the EPA to ensure within 8 years of promulgating a NESHAP that the risks are acceptable and that the MACT standards provide an ample margin of safety.

The statutory requirement to establish technology-based standards under CAA section 112 eliminated the requirement for the EPA to identify hazards to public health and the environment in order to justify regulation of HAP emissions from stationary sources, reflecting Congress's judgment that such emissions are inherently dangerous. See S. Rep. No. 101–228, at 148 (''The MACT standards are based on the performance of technology, and not on the health and environmental effects of the [HAP].''). The technology review required in CAA section 112(d)(6) further mandates that the EPA continually reassess standards to determine if additional reductions can be obtained, without evaluating the specific risk associated with the HAP emissions that would be reduced. Notably, Congress required the EPA to conduct the CAA section 112(d)(6) review of what additional reductions may be obtained based on new technology even after the EPA has conducted the one-time CAA section 112(f)(2) risk review and determined that the existing standard will protect the public with an ample margin of safety. The two requirements are distinct, and both are mandatory.

B. What is the Coal- and Oil-Fired EGU source category and how does the NESHAP regulate HAP emissions from the source category?

1. Summary of Coal- and Oil-Fired EGU Source Category and NESHAP Regulations

The EPA promulgated the Coal- and Oil-Fired EGU NESHAP (commonly referred to as MATS) on February 16, 2012 (77 FR 9304) (2012 MATS Final Rule). The standards are codified at 40 CFR part 63, subpart UUUUU. The coal- and oil-fired electric utility industry consists of facilities that burn coal or oil located at both major and area sources of HAP emissions. An existing affected source is the collection of coal- or oil-fired EGUs in a subcategory within a single contiguous area and under common control. A new affected source is each coal- or oil-fired EGU for which construction or reconstruction began

---

[8] Congress recognized as much: ''The Administrator may take the cost of achieving the maximum emission reduction and any non-air quality health and environmental impacts and energy requirements into account when determining the emissions limitation which is achievable for the sources in the category or subcategory. Cost considerations are reflected in the selection of emissions limitations which have been achieved in practice (rather than those which are merely theoretical) by sources of a similar type or character.'' A Legislative History of the Clean Air Act Amendments of 1990 (CAA Legislative History), Vol 5, pp. 8508–8509 (CAA Amendments of 1989; p. 168–169; Report of the Committee on Environment and Public Works S. 1630).

after May 3, 2011. An EGU is a fossil fuel-fired combustion unit of more than 25 megawatts (MW) that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MW electric output to any utility power distribution system for sale is also considered an EGU. The 2012 MATS Final Rule defines additional terms for determining rule applicability, including, but not limited to, definitions for ''coal-fired electric utility steam generating unit,'' ''oil-fired electric utility steam generating unit,'' and ''fossil fuel-fired.'' In 2028, the EPA expects the source category covered by this MACT standard to include 314 coal-fired steam generating units (140 GW at 157 facilities), 58 oil-fired steam generating units (23 GW at 35 facilities), and 5 IGCC units (0.8 GW at 2 facilities).

For coal-fired EGUs, the 2012 MATS Final Rule established standards to limit emissions of Hg, acid gas HAP (*e.g.,* HCl, HF), non-Hg HAP metals (*e.g.,* nickel, lead, chromium), and organic HAP (*e.g.,* formaldehyde, dioxin/furan). Emission standards for HCl serve as a surrogate for the acid gas HAP, with an alternate standard for SO_2 that may be used as a surrogate for acid gas HAP for those coal-fired EGUs with flue gas desulfurization (FGD) systems and SO_2 CEMS installed and operational. Standards for fPM serve as a surrogate for the non-Hg HAP metals. Work practice standards limit formation and emissions of organic HAP.

For oil-fired EGUs, the 2012 MATS Final Rule established standards to limit emissions of HCl and HF, total HAP metals (*e.g.,* Hg, nickel, lead), and organic HAP (*e.g.,* formaldehyde, dioxin/furan). Standards for fPM also serve as a surrogate for total HAP metals, with standards for total and individual HAP metals provided as alternative equivalent standards. Work practice standards limit formation and emissions of organic HAP.

MATS includes standards for existing and new EGUs for eight subcategories: three for coal-fired EGUs, one for IGCC EGUs, one for solid oil-derived fuel-fired EGUs (*i.e.,* petroleum coke-fired), and three for liquid oil-fired EGUs. EGUs in seven of the subcategories are subject to numeric emission limits for all the pollutants described above except for organic HAP (limited-use liquid oil-fired EGUs are not subject to numeric emission limits). Emissions of organic HAP are regulated by a work practice standard that requires periodic combustion process tune-ups. EGUs in the subcategory of limited-use liquid oil-fired EGUs with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input are also subject to a work practice standard consisting of periodic combustion process tune-ups but are not subject to any numeric emission limits. Emission limits for existing EGUs and additional information of the history and other requirements of the 2012 MATS Final Rule are available in the 2023 Proposal preamble (88 FR 24854).

2. Public Health and Environmental Hazards Associated With Emissions From Coal- and Oil-Fired EGUs

Coal- and oil-fired EGUs are a significant source of numerous HAP that are associated with adverse effects to human health and the environment, including Hg, HF, HCl, selenium, arsenic, chromium, cobalt, nickel, hydrogen cyanide, beryllium, and cadmium emissions. Hg is a persistent and bioaccumulative toxic metal that, once released from power plants into the ambient air, can be readily transported and deposited to soil and aquatic environments where it is transformed by microbial action into methylmercury.[9] Methylmercury bioaccumulates in the aquatic food web eventually resulting in highly concentrated levels of methylmercury within the larger and longer-living fish (*e.g.,* carp, catfish, trout, and perch), which can then be consumed by humans.

Of particular concern is chronic prenatal exposure via maternal consumption of foods containing methylmercury. Elevated exposure has been associated with developmental neurotoxicity and manifests as poor performance on neurobehavioral tests, particularly on tests of attention, fine motor function, language, verbal memory, and visual-spatial ability. Evidence also suggests potential for adverse effects on the cardiovascular system, adult nervous system, and immune system, as well as potential for causing cancer. Because the impacts of the neurodevelopmental effects of methylmercury are greatest during periods of rapid brain development, developing fetuses, infants, and young children are particularly vulnerable. Children born to populations with high fish consumption (*e.g.,* people consuming fish as a dietary staple) or impaired nutritional status may be especially susceptible to adverse neurodevelopmental outcomes. These dietary and nutritional risk factors are often particularly pronounced in vulnerable communities with people of color and low-income populations that have historically faced economic and environmental injustice and are overburdened by cumulative levels of pollution. In addition to adverse neurodevelopmental effects, there is evidence that exposure to methylmercury in humans and animals can have adverse effects on both the developing and adult cardiovascular system.

Along with the human health hazards associated with methylmercury, it is well-established that birds and mammals are also exposed to methylmercury through fish consumption (Mercury Study). At higher levels of exposure, the harmful effects of methylmercury include slower growth and development, reduced reproduction, and premature mortality. The effects of methylmercury on wildlife are variable across species but have been observed in the environment for numerous avian species and mammals including polar bears, river otters, and panthers.

EGUs are also the largest source of HCl, HF, and selenium emissions, and are a major source of metallic HAP emissions including arsenic, chromium, nickel, cobalt, and others. Exposure to these HAP, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (*e.g.,* pneumonitis, decreased pulmonary function, pneumonia, or lung damage; detrimental effects on the central nervous system; damage to the kidneys) and alimentary effects (such as nausea and vomiting). As of 2021, three of the key metal HAP emitted by EGUs (arsenic, chromium, and nickel) have been classified as human carcinogens, while three others (cadmium, selenium, and lead) are classified as probable human carcinogens. Overall (metal and nonmetal), the EPA has classified four of the HAP emitted by EGUs as human carcinogens and five as probable human carcinogens.

While exposure to HAP is associated with a variety of adverse effects, quantifying the economic value of these impacts remains challenging. Epidemiologic studies, which report a central estimate of population-level risk, are generally used in an air pollution benefits assessment to estimate the number of attributable cases of events. Exposure to HAP is typically more uneven and more highly concentrated among a smaller number of individuals than exposure to criteria pollutants.

---

[9] U.S. EPA. 1997, Mercury Study Report to Congress, EPA–452/R–97–003 (December 1997); *see also* 76 FR 24976 (May 3, 2011); 80 FR 75029 (December 1, 2015).

Hence, conducting an epidemiologic study for HAP is inherently more challenging; for starters, the small population size means such studies often lack sufficient statistical power to detect effects (particularly outcomes like cancer, for which there can exist a multi-year time lag between exposure and the onset of the disease). By contrast, sufficient power generally exists to detect effects for criteria pollutants because exposures are ubiquitous and a variety of methods exist to characterize this exposure over space and time.

For the reasons noted above, epidemiologic studies do not generally exist for HAP. Instead, the EPA tends to rely on experimental animal studies to identify the range of effects which may be associated with a particular HAP exposure. Human controlled clinical studies are often limited due to ethical barriers (*e.g.,* knowingly exposing someone to a carcinogen). Generally, robust data are needed to quantify the magnitude of expected adverse impacts from varying exposures to a HAP. These data are necessary to provide a foundation for quantitative benefits analyses but are often lacking for HAP, made even more challenging by the wide array of HAP and possible noncancer HAP effects.

Finally, estimating the economic value of HAP is made challenging by the human health endpoints affected. For example, though EPA can quantify the number and economic value of HAP-attributable deaths resulting from cancer, it is difficult to monetize the value of reducing an individual's potential cancer risk attributable to a lifetime of HAP exposure. An alternative approach of conducting willingness to pay studies specifically on risk reduction may be possible, but such studies have not yet been pursued.

C. Summary of the 2020 Residual Risk Review

As required by CAA section 112(f)(2), the EPA conducted the residual risk review (2020 Residual Risk Review) in 2020, 8 years after promulgating the 2012 MATS Final Rule, and presented the results of the review, along with our decisions regarding risk acceptability, ample margin of safety, and adverse environmental effects, in the 2020 Final Action. The results of the risk assessment are presented briefly in table 3 of this document, and in more detail in the document titled *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule* (risk document for the final rule), available in the docket (Document ID No. EPA–HQ–OAR–2018–0794–4553). The EPA summarized the results and findings of the 2020 Residual Risk Review in the preamble of the 2023 Proposal (88 FR 24854), and additional information concerning the residual risk review can be found in our *National-Scale Mercury Risk Estimates for Cardiovascular and Neurodevelopmental Outcomes for the National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Finding; Notice of Proposed Rulemaking* memorandum (Document ID No. EPA–HQ–OAR–2018–0794–4605).

BILLING CODE 6560–50–P

Table 3. Coal- and Oil-Fired EGU Inhalation Risk Assessment Results in the 2020 Final Action (85 FR 31286; May 22, 2020)

Number of Facilities[1]	Maximum Individual Cancer Risk (in 1 million)[2]		Population at Increased Risk of Cancer ≥ 1-in-1 million		Annual Cancer Incidence (cases per year)		Maximum Chronic Noncancer TOSHI[3]		Maximum Screening Acute Noncancer HQ[4]
322	Based on . . .		Based on . . .		Based on . . .		Based on . . .		Based on Actual Emissions Level
	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	Actual Emissions Level	Allowable Emissions Level	
	9	10	193,000	636,000	0.04	0.1	0.2	0.4	HQ_{REL} = 0.09 (arsenic)

[1] Number of facilities evaluated in the risk analysis. At the time of the risk analysis there were an estimated 323 facilities in the Coal- and Oil-Fired EGU source category; however, one facility is located in Guam, which was beyond the geographic range of the model used to estimate risks. Therefore, the Guam facility was not modeled and the emissions for that facility were not included in the assessment.

[2] Maximum individual excess lifetime cancer risk due to HAP emissions from the source category.

[3] Maximum target organ-specific hazard index (TOSHI). The target organ systems with the highest TOSHI for the source category are respiratory and immunological.

[4] The maximum estimated acute exposure concentration was divided by available short-term threshold values to develop an array of hazard quotient (HQ) values. HQ values shown use the lowest available acute threshold value, which in most cases is the reference exposure level (REL). When an HQ exceeds 1, we also show the HQ using the next lowest available acute dose-response value.

BILLING CODE 6560–50–C

D. Summary of the 2020 Technology Review

Pursuant to CAA section 112(d)(6), the EPA conducted a technology review (2020 Technology Review) in the 2020 Final Action, which focused on identifying and evaluating developments in practices, processes, and control technologies for the emission sources in the source category that occurred since the 2012 MATS Final Rule was promulgated. Control technologies typically used to minimize emissions of pollutants that have numeric emission limits under the 2012 MATS Final Rule include electrostatic precipitators (ESPs) and fabric filters (FFs) for control of fPM as a surrogate for non-Hg HAP metals; wet scrubbers, dry scrubbers, and dry sorbent injection for control of acid gases (SO_2, HCl, and HF); and activated carbon injection (ACI) and other Hg-specific technologies for control of Hg. The EPA determined that the existing air pollution control technologies that were in use were well-established and provided the capture efficiencies necessary for compliance with the MATS emission limits. Based on the effectiveness and proven reliability of these control technologies, and the relatively short period of time since the promulgation of the 2012 MATS Final Rule, the EPA did not identify any developments in practices, processes, or control technologies, nor any new technologies or practices, for the control of non-Hg HAP metals, acid gas HAP, or Hg. However, in the 2020 Technology Review, the EPA did not consider developments in the cost and effectiveness of these proven technologies, nor did the EPA evaluate the current performance of emission reduction control equipment and strategies at existing MATS-affected EGUs, to determine whether revising the standards was warranted. Organic HAP, including emissions of dioxins and furans, are regulated by a work practice standard that requires periodic burner tune-ups to ensure good combustion. The EPA found that this work practice continued to be a practical approach to ensuring that combustion equipment was maintained and optimized to run to reduce emissions of organic HAP and continued to be more effective than establishing a numeric standard that cannot reliably be measured or monitored. Based on the effectiveness and proven reliability of the work practice standard, and the relatively short amount of time since the promulgation of the 2012 MATS Final Rule, the EPA did not identify any developments in work practices nor any new work practices or operational procedures for this source category regarding the additional control of organic HAP.

After conducting the 2020 Technology Review, the EPA did not identify developments in practices, processes, or control technologies and, thus, did not propose changes to any emission standards or other requirements. More information concerning that technology review is in the memorandum titled Technology Review for the Coal- and Oil-Fired EGU Source Category, available in the docket (Document ID No. EPA–HQ–OAR–2018–0794–0015), and in the February 7, 2019, proposed rule. 84 FR 2700. On May 20, 2020, the EPA finalized the first technology review required by CAA section 112(d)(6) for the coal- and oil-fired EGU source category regulated under MATS. Based on the results of that technology review, the EPA found that no revisions to MATS were warranted. See 85 FR 31314 (May 22, 2020).

E. Summary of the EPA's Review of the 2020 RTR and the 2023 Proposed Revisions to the NESHAP

Pursuant to CAA section 112(d)(6), the EPA conducted a review of the 2020 Technology Review and presented the results of this review, along with our proposed decisions, in the 2023 Proposal. The results of the technology review are presented briefly below in this preamble. More detail on the proposed technology review is in the memorandum *2023 Technology Review for the Coal- and Oil-Fired EGU Source Category* (''2023 Technical Memo'') (Document ID No. EPA–HQ–OAR–2018–0794–5789).

Based on the results of the technology review, the EPA proposed to lower the fPM standard, the surrogate for non-Hg HAP metals, for coal-fired EGUs from 0.030 lb/MMBtu to 0.010 lb/MMBtu. The Agency solicited comment on the control technology effectiveness and cost assumptions used in the proposed rule, as well as on a more stringent fPM limit of 0.006 lb/MMBtu or lower. Additionally, the Agency proposed to require the use of PM CEMS for all coal-fired, oil-fired, and IGCC EGUs for demonstrating compliance with the fPM standard. As the Agency proposed to require PM CEMS for compliance demonstration, we also proposed to remove the LEE option, a program based on infrequent stack testing, for fPM and non-Hg HAP metals. As EGUs would be required to demonstrate compliance with PM CEMS, the Agency also proposed to remove the alternate emission standards for non-Hg HAP metals and total HAP metals, because almost all regulated sources have chosen to demonstrate compliance with the non-Hg HAP metal standards by demonstrating compliance with the surrogate fPM standard, and solicited comment on prorated metal limits (adjusted proportionally according to the level of the final fPM standard), should the Agency not finalize the removal of the non-Hg HAP metals limits.

The Agency also proposed to lower the Hg emission standard for lignite-fired EGUs from 4.0 lb/TBtu to 1.2 lb/TBtu and solicited comment on the performance of Hg controls and on cost and effectiveness of control strategies to meet more stringent Hg standards. Lastly, the EPA did not identify new developments in control technologies or improved methods of operation that would warrant revisions to the Hg emission standards for non-lignite EGUs, for the organic HAP work practice standards, for the acid gas standards, or for standards for oil-fired EGUs. Therefore, the Agency did not propose changes to these standards in the 2023 Proposal but did solicit comment on the EPA's proposed findings that no revisions were warranted and on the appropriateness of the existing standards.

Additionally, the EPA proposed to remove one of the two options for defining the startup period for MATS-affected EGUs.

In the 2023 Proposal, the EPA determined not to reopen the 2020 Residual Risk Review, and accordingly did not propose any revisions to that review. As the EPA explained in the proposal, the EPA found in the 2020 RTR that risks from the Coal- and Oil-Fired EGU source category due to emissions of air toxics are acceptable and that the existing NESHAP provides an ample margin of safety to protect public health. As noted in the proposal, the EPA also acknowledges that it received a petition for reconsideration from environmental organizations that, in relevant part, sought the EPA's reconsideration of certain aspects of the 2020 Residual Risk Review. The EPA granted in part the environmental organizations' petition which sought the EPA's review of startup and shutdown provisions in the 2023 Proposal, 88 FR 24885, and the EPA continues to review and will respond to other aspects of the petition in a separate action.[10]

III. What is included in this final rule?

This action finalizes the EPA's determinations pursuant to the RTR provisions of CAA section 112 for the Coal- and Oil-Fired EGU source category and amends the Coal- and Oil-Fired EGU NESHAP based on those determinations. This action also finalizes changes to the definition of startup for this rule. This final rule includes changes to the 2023 Proposal after consideration of comments received during the public comment period described in sections IV., V., VI., and VII. of this preamble.

A. What are the final rule amendments based on the technology review for the Coal- and Oil-Fired EGU source category?

We determined that there are developments in practices, processes, and control technologies that warrant revisions to the MACT standards for this source category. Therefore, to satisfy the requirements of CAA section 112(d)(6), we are revising the MACT standards by revising the fPM limit for existing coal-fired EGUs from 0.030 lb/MMBtu to 0.010 lb/MMBtu and requiring the use of PM CEMS for coal and oil-fired EGUs to demonstrate compliance with the revised fPM standard, as proposed. We are also finalizing, as proposed, a Hg limit for lignite-fired EGUs of 1.2 lb/TBtu, which aligns with the existing Hg limit that has been in effect for other coal-fired EGUs since 2012. This revised Hg limit for lignite-fired EGUs is more stringent than the limit of 4.0 lb/TBtu that was finalized for such units in the 2012 MATS Final Rule. The rationale for these changes is discussed in more detail in sections IV. and V. below.

Based on comments received during the public comment period, the EPA is not finalizing the proposed removal of the non-Hg HAP metals limits for existing coal-fired EGUs (see section V.). Additionally, this final rule is requiring the use of PM CEMS for compliance demonstration for coal- and oil-fired EGUs (excluding EGUs in the limited-use liquid oil-fired subcategory), but not for IGCC EGUs (see section VI.).

Because this final rule includes revisions to the emissions standards for fPM as a surrogate for non-Hg HAP metals for existing coal-fired EGUs, the fPM emission standard compliance demonstration requirements, the Hg emission standard for lignite-fired EGUs, and the definition of ''startup,'' the EPA intends each portion of this rule to be severable from each other as it is multifaceted and addresses several distinct aspects of MATS for independent reasons. This includes the revised emission standard for fPM as a surrogate for non-Hg HAP metals and the fPM compliance demonstration requirement to utilize PM CEMS. While the EPA considered the technical feasibility of PM CEMS in establishing the revised fPM standard, the EPA finds there are independent reasons for adopting each revision to the standards, and that each would continue to be workable without the other in the place.

---

[10] See Document ID No. EPA–HQ–OAR–2018–0794–4565 at *https://www.regulations.gov.*

The EPA intends that the various pieces of this package be considered independent of each other. For example, the EPA notes that our judgments regarding developments in fPM control technology for the revised fPM standard as a surrogate for non-Hg HAP metals largely reflect that the fleet was reporting fPM emission rates well below the current standard and with lower costs than estimated during promulgation of the 2012 MATS Final Rule; while our judgments regarding the ability for lignite-fired EGUs to meet the same standard for Hg emissions as other coal- and oil-fired EGUs rest on a separate analysis specific to lignite-fired units. Thus, the revised fPM surrogate emissions standard is feasible and appropriate even absent the revised Hg standard for lignite-fired units, and vice versa. Similarly, the EPA is finalizing changes to the fPM compliance demonstration requirement based on the technology's ability to provide increased transparency for owners and operators, regulators, and the public; and the EPA is finalizing changes to the startup definition based on considerations raised by environmental groups in petitions for reconsideration. Both of these actions are independent from the EPA's revisions to the fPM surrogate standard, and the Hg standard for lignite-fired units. Accordingly, the EPA finds that each set of standards is severable from each other set of standards.

Finally, the EPA finds that implementation of each set of standards, compliance demonstration requirements, and revisions to the startup definition are independent. That is, a source can abide by any one of these individual requirements without abiding by any others. Thus, the EPA's overall approach to this source category continues to be fully implementable even in the absence of any one or more of the elements included in this final rule.

Thus, the EPA has independently considered and adopted each portion of this final rule (including the revised fPM emission standard as a surrogate for non-Hg HAP metals, the fPM compliance demonstration requirement, the revised Hg emission standard for lignite-fired units, and the revised startup definition) and each is severable should there be judicial review. If a court were to invalidate any one of these elements of the final rule, the EPA intends the remainder of this action to remain effective. Importantly, the EPA designed the different elements of this final rule to function sensibly and independently. Further, the supporting bases for each element of the final rule reflect the Agency's judgment that the element is independently justified and appropriate, and that each element can function independently even if one or more other parts of the rule has been set aside.

B. What other changes have been made to the NESHAP?

The EPA is finalizing, as proposed, the removal of the work practice standards of paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042. Under the first option, startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Under the second option, startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on-site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes, whichever is earlier. The final rule requires that all EGUs use the work practice standards in paragraph (1) of the definition of ''startup,'' which is already being used by the majority of EGUs.

C. What are the effective and compliance dates of the standards?

The revisions to the MACT standards being promulgated in this action are effective on July 8, 2024. The compliance date for affected coal-fired sources to comply with the revised fPM limit of 0.010 lb/MMBtu and for lignite-fired sources to meet the lower Hg limit of 1.2 lb/TBtu is 3 years after the effective date of the final rule. The Agency believes this timeline is as expeditious as practicable considering the potential need for some sources to upgrade or replace pollution controls. As discussed elsewhere in this preamble, we are adding a requirement that compliance with the fPM limit be demonstrated using PM CEMS. Based on comments received during the comment period and our understanding of suppliers of PM CEMS, the EPA is finalizing the requirement that affected sources use PM CEMS for compliance demonstration by 3 years after the effective date of the final rule. The compliance date for existing affected sources to comply with amendments pertaining to the startup definition is 180 days after the effective date of the final rule, as few EGUs are affected, and changes needed to comply with paragraph (1) of startup are achievable by all EGUs at little to no additional expenditures. All affected facilities remain subject to the current requirements of 40 CFR part 63, subpart UUUUU, until the applicable compliance date of the amended rule.

The EPA has considered the concerns raised by commenters that these compliance deadlines could affect electric reliability and concluded that given the flexibilities detailed further in this section, the requirements of the final rule for existing sources can be met without adversely impacting electric reliability. In particular, the EPA notes the flexibility of permitting authorities to allow, if warranted, a fourth year for compliance under CAA section 112(i)(3)(B). This flexibility, if needed, would address many of the concerns that commenters raised. Furthermore, in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides additional flexibilities to bring sources into compliance while maintaining reliability.

The EPA notes that similar concerns regarding reliability were raised about the 2012 MATS Final Rule—a rule that projected the need for significantly greater installation of controls and other capital investments than this current revision. In the 2012 MATS Final Rule, the EPA emphasized that most units should be able to comply with the requirements of the final rule within 3 years. However, the EPA also made it clear that permitting authorities have the authority to grant a 1-year compliance extension where necessary, in a range of situations described in the 2012 MATS Final Rule preamble.[11] The EPA's Office of Enforcement and Compliance Assurance (OECA) also issued the MATS Enforcement Response policy (Dec. 16, 2011)[12] which described the approach regarding the issue of CAA section 113(a) administrative orders with respect to the sources that must operate in noncompliance with the MATS rule for up to 1 year to address specific documented reliability concerns. While several affected EGUs requested and were granted a 1-year CAA section 112(i)(3)(B) compliance extension by their permitting authority, OECA only issued five administrative orders in connection with the Enforcement Response policy. The 2012 MATS Final Rule was ultimately implemented over the 2015—2016 timeframe without challenges to grid reliability.

---

[11] 77 FR 9406.

[12] *https://www.epa.gov/enforcement/enforcement-response-policy-mercury-and-air-toxics-standard-mats.*

IV. What is the rationale for our final decisions and amendments to the filterable PM (as a surrogate for non-Hg HAP metals) standard and compliance options from the 2020 Technology Review?

In this section, the EPA provides descriptions of what we proposed, what we are finalizing, our rationale for the final decisions and amendments, and a summary of key comments and responses related to the emission standard for fPM, non-Hg HAP metals, and the compliance demonstration options. For all comments not discussed in this preamble, comment summaries and the EPA's responses can be found in the comment summary and response document *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review Proposed Rule Response to Comments,* available in the docket.

Based on its review, the EPA is finalizing a revised non-Hg HAP metal surrogate fPM emission standard for all existing coal-fired EGUs of 0.010 lb/MMBtu and is requiring that all coal- and oil-fired EGUs demonstrate compliance with the revised fPM emission standard by using PM CEMS. The revised fPM standard will ensure that the entire fleet of coal-fired EGUs achieves performance levels that are consistent with those of the vast majority of regulated units operating today—*i.e.,* that the small minority of units that currently emit significantly higher levels of HAP than their peers use proven technologies to reduce their HAP to the levels achieved by the rest of the fleet. Further, the EPA finds that a 0.010 lb/MMBtu fPM emission standard is the lowest level currently compatible with PM CEMS for demonstrating compliance, which the EPA finds provides significant benefits including increased transparency regarding emissions performance for sources, regulators, and the surrounding communities; and real-time identification of when control technologies are not performing as expected, allowing for quicker repairs. In addition, the rule's current requirement to shift electronic reporting of PM CEMS data to the Emissions Collection and Monitoring Plan System (ECMPS) will enable regulatory authorities, nearby citizens, and others, including members of the public and media, to quickly and easily locate, review, and download fPM emissions using simple, user-directed inquiries. An enhanced, web-based version of ECMPS (ECMPS 2.0) is currently being prepared that will ease data editing, importing, and exporting and is expected to be available prior to the date by which EGUs are required to use PM CEMS.

A. What did we propose pursuant to CAA section 112(d)(6) for the Coal- and Oil-Fired EGU source category?

1. Proposed Changes to the Filterable PM Standard

The EPA proposed to lower the fPM limit, a surrogate for total non-Hg HAP metals, for coal-fired EGUs from 0.030 lb/MMBtu to 0.010 lb/MMBtu. The EPA further solicited comment on an emission standard of 0.006 lb/MMBtu or lower. The EPA did not propose any changes to the fPM emission standard for oil-fired EGUs or for IGCC units. The EPA also proposed to remove the total and individual non-Hg HAP metals emission limits. The EPA also solicited comment on adjusting the total and individual non-Hg HAP metals emission limits proportionally to the revised fPM limit rather than eliminating the limits altogether.

2. Proposed Changes to the Requirements for Compliance Demonstration

The EPA proposed to require that all coal- and oil-fired EGUs (IGCC units are discussed in section VI.) use PM CEMS to demonstrate compliance with the fPM emission limit. The EPA also proposed to remove the option of demonstrating compliance using infrequent stack testing and the LEE program (where stack testing occurs quarterly for 3 years, then every third year thereafter) for both PM and non-Hg HAP metals.

B. How did the technology review change for the Coal- and Oil-Fired EGU source category?

1. Filterable PM Emission Standard

Commenters provided both supportive and opposing arguments for issues regarding the fPM limit that were presented in the proposed review of the 2020 Technology Review. Comments received on the proposed fPM limit for coal-fired EGUs, along with additional analyses, did not change the Agency's conclusions that were presented in the 2023 Proposal, and, therefore, the Agency is finalizing the 0.010 lb/MMBtu fPM emission limit for existing coal-fired EGUs, as proposed.

Additionally, commenters urged the Agency to retain the option of complying with individual non-Hg HAP metal (*e.g.,* lead, arsenic, chromium, nickel, and cadmium) emission rates or with a total non-Hg HAP metal emission rate. After consideration of public comments, the Agency is finalizing updated limits for non-Hg HAP metals and total non-Hg HAP metals that have been reduced proportional to the reduction of the fPM emission limit from 0.030 lb/MMBtu to the new final fPM emission limit of 0.010 lb/MMBtu. EGU owners or operators who would choose to comply with the non-Hg HAP metals emission limits instead of the fPM limit must request and receive approval of a non-Hg HAP metal CMS as an alternative test method (*e.g.,* multi-metal CMS) under the provisions of 40 CFR 63.7(f).

2. Compliance Demonstration Options

Comments received on the compliance demonstration options for coal- and oil-fired EGUs also did not change the results of the technology review, therefore the Agency is finalizing the use of PM CEMS for compliance demonstration purposes and removing the fPM and non-Hg HAP metals LEE options for all coal-fired EGUs and for oil-fired EGUs (except those in the limited use liquid oil-fired EGU subcategory). The Agency received comments that some PM CEMS that are currently correlated for the 0.030 lb/MMBtu fPM emission limit may experience some difficulties should re-correlation be necessary at a lower fPM standard. Based on these comments and on additional review of PM CEMS test reports, as mentioned in sections IV.C.2. and IV.D.2., the Agency has made minor technical revisions to shift the basis of correlation testing from sampling a minimum volume per run to collecting a minimum mass or minimum sample volume per run and has adjusted the quality assurance (QA) criterion otherwise associated with the new emission limit. These changes will enable PM CEMS to be properly certified for use in demonstrating compliance with the lower fPM standard with a high degree of accuracy and reliability.

C. What key comments did we receive on the filterable PM and compliance options, and what are our responses?

1. Comments on the Filterable PM Emission Standard

Comment: Some commenters supported the proposed fPM limit of 0.010 lb/MMBtu as reasonable and achievable, noting that this limit is slightly greater than the fPM emission limit required for new and reconstructed units. Additionally, commenters stated CAA section 112 was intended to improve the performance of lagging industrial sources and that a standard that falls far behind what the vast majority of sources have already achieved, as the current standard does, is inadequate. Other commenters opposed the proposed fPM limit of 0.010 lb/MMBtu as too stringent. For instance, some commenters stated that the EPA did not provide adequate support for the proposed limit. Other commenters stated that the fact that the vast majority of units are achieving emission rates below the current limit does not constitute ''developments in practices, processes, and control technologies.''

Response: The EPA disagrees that the Agency has not adequately supported the proposed fPM limit. As described in the proposal preamble, the Agency conducted a review of the 2020 Technology Review pursuant to CAA section 112(d)(6), which focused on identifying and evaluating developments in practices, processes, and control technologies for the emission sources in the source category that occurred since promulgation of the 2012 MATS Final Rule. Based on that review, the EPA found that a majority of sources were not only reporting fPM emissions significantly below the current emission limit, but also that the fleet achieved lower fPM rates at lower costs than the EPA estimated when it promulgated the 2012 MATS Final Rule. The EPA explains these findings in more detail in section IV.D.1. of this preamble and elsewhere in the record. Further, the EPA finds that there are technological developments and improvements in PM control technology, which also controls non-Hg HAP metals, since the 2012 MATS Final Rule that informed the 2023 Proposal and this action, as discussed further in section IV.D.1. below. For example, industry has implemented ''best practices'' for monitoring ESP operation more carefully, and more durable materials have been adopted for FFs since the 2012 MATS Final Rule. The EPA also finds that these are cognizable developments for purposes of CAA section 112(d)(6). As other commenters noted, in *National Association for Surface Finishing* v. *EPA,* 795 F.3d 1, 11 (D.C. Cir. 2015), the D.C. Circuit found that the EPA ''permissibly identified and took into account cognizable developments'' based on the EPA's interpretation of the term as ''not only wholly new methods, but also technological improvements.'' Similarly, here the EPA identified a clear trend in control efficiency, costs, and technological improvements, which the EPA is accounting for in this action. Further, as discussed elsewhere in this section and in section IV.D.1. of this preamble, the EPA finds case law and substantial administrative precedent support the EPA's decision to update the fPM limit based upon these developments.

Comment: Many commenters recommended that the EPA add a compliance margin in its achievability assumptions. These commenters conveyed that most EGUs typically operate well below the limit to allow for a compliance margin in the event of an equipment malfunction or failure, which they encouraged the EPA to consider when setting new limits. These commenters claimed that with a proposed fPM limit of 0.010 lb/MMBtu, an appropriate design margin of 20 percent necessitates that control technologies must be able to achieve a limit of 0.008 lb/MMBtu or lower in practice. They also expressed concerns that the EPA did not take design margin into consideration in the cost analysis. They stated that by not including the need for a design margin, which the EPA has acknowledged the need for in at least two of the Agency's publications (*NESHAP Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired EGUs,* Document ID No. EPA–HQ–OAR–2009–0234–20223 and *PM CEMS Capabilities Summary for Performance Specification 11, NSPS, and MACT Rules,* Document ID No. EPA–HQ–OAR–2018–0794–5828), the EPA underpredicted the number of units that would require retrofits. These commenters stated that the combination of a very low fPM limit and having to account for the measurement uncertainty and correlation methodology of PM CEMS would likely necessitate an ''operational target limit'' of 50 percent of the applicable limit. Some commenters referenced the National Rural Electric Cooperative Association (NRECA) technical evaluation for the 2023 Proposal titled *Technical Comments on National Emissions Standard for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology.*[13] They said that, even using the EPA's unrealistic ''baseline fPM rates'' and the lowest possible compliance margin of 20 percent, the NRECA technical evaluation estimated that 37 units—almost twice as many as the EPA's estimate—would be required to take substantial action to comply with the proposed limit.

Response: The EPA agrees that most facility operators normally target an emission level below the emission limit by incorporating a compliance margin or margin of error in case of equipment malfunctions or failures. As the commenters noted, the Agency has previously recognized that some operators target an emission level 20 to 50 percent below the limit. However, no commenters provided data to suggest that ESPs or FF are unable to achieve a lower fPM limit. Furthermore, the Agency does not prescribe specifically how an EGU controls its emissions or how the unit operates. The choice to target a lower-level emission rate for a compliance margin is the sole decision of owners and operators. For facilities with more than one EGU in the same subcategory, owners or operators may find emissions averaging (40 CFR 63.10009), coupled with or without a compliance margin, could help the facility attain and maintain emission limits as an effective, low-cost approach. Additionally, no commenters provided data to indicate that every owner or operator aims to comply with the fPM limit with the same compliance margin. Because some operators might aim for a larger compliance margin than others, it would be difficult to select a particular assumption about compliance margin for the cost analysis. Every operator plans for compliance differently and the EPA cannot know every operator's plans for a compliance margin. Even if the EPA were to assume a 20 percent compliance margin in its evaluation of PM controls, the results of the analysis would not change the EPA's decision to adopt a lower fPM limit. Specifically, a 20 percent compliance margin assumption to a fPM limit of 0.010 lb/MMBtu would increase the number of affected EGUs from 33 to 53 (14.1 to 23.9 GW affected capacity) and the annual compliance costs from $87.2M to $147.7M. The number of EGUs that demonstrated an ability to meet the lower fPM limit, but do not do so on average and therefore would require O&M, would increase from 17 to 27 (including the compliance margin). Similarly, the number of ESP upgrades (previously 11) and bag upgrades (previously 3) would also increase (to 20 and 4, respectively). There would be no change in the number of new FF installs. Therefore, cost-effectiveness values for fPM and individual and total non-Hg HAP metals would only increase slightly. Moreover, the 30-boiler operating day averaging period using PM CEMS for compliance

---

[13] *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology.* Cichanowicz, *et al.* June 19, 2023. Attachment A to Document ID No. EPA–HQ–OAR–2018–0794–5994.

demonstration provides flexibility for owners and operators to account for equipment malfunctions, operational variability, and other issues. Lastly, as described in the 2023 Proposal, and updated here, the vast majority of coal-fired EGUs are reporting fPM emissions well below the revised fPM limit. For instance, the median fPM rate of the 296 coal-fired EGUs assessed in the 2024 Technical Memo is 0.004 lb/MMBtu,[14] or 60 percent below the revised fPM limit of 0.010 lb/MMBtu. The median fPM rate of a quarter of the best performing sources (N=74) is 0.002 lb/MMBtu, about 80 percent below the revised fPM limit of 0.010 lb/MMBtu. Therefore, for these reasons, the EPA disagrees with commenters that a compliance margin needs to be considered in the cost analysis.

The updated PM analysis, detailed in the memorandum *2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category* (''2024 Technical Memo'') available in the docket, estimates that the number of EGUs that will need to improve their fPM emission rate to achieve a 0.010 lb/MMBtu limit has increased from the 20 EGUs assumed in the 2023 Proposal to 33 EGUs, which is more consistent with the NRECA technical evaluation estimate of 37 EGUs. This increase is a result of updated methodology that utilizes both the lowest achieved fPM rate (*i.e.,* the lowest quarter's 99th percentile) and the average fPM rate across all quarterly data when assessing PM upgrade and costs assumptions for the evaluated limits. The Agency disagrees with the commenters, however, that the 37 EGUs in the NRECA technical evaluation would require ''substantial action to comply with the proposed standard.'' In the Agency's revised analysis, only 13 EGUs would require capital investments to meet a fPM limit of 0.010 lb/MMBtu. Of these, only two EGUs at one facility (Colstrip) currently without the most effective PM controls are projected to require installation of a FF, the costliest PM control upgrade option, to meet 0.010 lb/MMBtu. The remaining nine EGUs projected by the EPA to require capital investments are estimated to require various levels of ESP upgrades. The EPA estimates that more than half (20 EGUs) would be able to comply without any capital investments and would instead require improvements to their existing FF or ESP as they have already demonstrated the ability to meet the limit, but do not do so on average.

Comment: Some commenters stated that cost effectiveness is an important consideration in technology reviews under CAA section 112(d)(6) and acknowledged that the EPA undertook cost-effectiveness analyses for the three fPM standards on which the Agency sought comment. However, the commenters stated, the NRECA technical evaluation found meaningful errors in the EPA's cost analysis, including unreasonably low capital cost estimates for ESP rebuilds and a failure to consider the variability of fPM due to changes in operation or facility design, by not utilizing a compliance margin. They asserted that these errors resulted in sizeable cost-effectiveness underestimates that eroded the EPA's overall determination that the proposed fPM limit is cost-effective. These commenters also asserted that the EPA's rationale was arbitrary on its face because it reversed, without explanation, the EPA's prior acknowledgements that a cost-effectiveness analysis should account for the cost effectiveness of controls at each affected facility and not simply on an aggregate nationwide basis. They stated that facility-specific costs should factor into the EPA's assessment of what is ''necessary'' pursuant to the provisions of CAA section 112(d)(6) and CAA section 112(f)(2).

Some commenters asserted that, even using the EPA's cost-effectiveness figures, the proposed 0.010 lb/MMBtu limit is not cost-effective. These commenters stated that the EPA's proposal to revise the fPM standard to 0.010 lb/MMBtu based on a cost-effectiveness estimate of up to $14.7 million per ton of total non-Hg HAP metals removed (equivalent to $44,900 per ton of fPM removed) is inconsistent with the EPA's prior actions because the cost-effectiveness estimate is substantially higher than estimates the Agency has previously found to be not cost-effective. They further said that, in the past, the EPA has decided against revising fPM standards based on cost-effectiveness estimates substantially lower than the cost-effectiveness estimates here. They said that the EPA should follow these precedents and acknowledge that $12.2 to $14.7 million per ton of non-Hg HAP metals reduced is not cost-effective. They argued that the Agency should not finalize the proposed standard of 0.010 lb/MMBtu for that reason. Further, these commenters argued that the alternative, more stringent limit of 0.006 lb/MMBtu is even less cost-effective at $25.6 million per ton of non-Hg HAP metals reduced, so it should not be considered either.

The commenters provided the following examples of previous rulemakings where EPA found controls to not be cost-effective:

- In the Petroleum Refinery Sector technology review,[15] the EPA declined to revise the fPM emission limit for existing fluid catalytic cracking units after finding that it would cost $10 million per ton of total non-Hg HAP metals reduced (in that case, equivalent to $23,000 per ton of fPM reduced), which was not cost-effective.
- In the Iron Ore Processing technology review,[16] the EPA declined to revise the non-Hg HAP metals limit after finding that installing wet scrubbers would cost $16 million per ton of non-Hg HAP metals reduced, which was not cost-effective.
- In the Integrated Iron and Steel Manufacturing Facilities technology review,[17] the EPA declined to revise the non-Hg HAP metals limit after finding that upgrading all fume/flame suppressants at blast furnaces to baghouses would cost $7 million per ton of non-Hg HAP metals reduced, which was not cost-effective. The Agency made a similar finding for a proposed limit that would have cost $14,000 per ton of volatile HAP reduced.
- In the Portland Cement Manufacturing beyond-the-floor analysis,[18] the EPA declined to impose a more stringent non-Hg HAP metals limit because it resulted in ''significantly higher cost effectiveness for PM than EPA has accepted in other NESHAP.'' The EPA noted in that rulemaking that it had previously ''reject[ed] $48,501 per ton of PM as not cost-effective for PM,'' and noted prior EPA statements in a subsequent rulemaking providing that $268,000 per ton of HAP removed was a higher cost-effectiveness estimate than the EPA had accepted in other NESHAP rulemakings.

In contrast, other commenters focused on the EPA's estimated cost-effective estimates for fPM (which is a surrogate for non-Hg HAP metals) and argued that

---

[14] For the revised fPM analysis, the EPA uses two methods to assess the performance of the fleet: average and the 99th percentile of the lowest quarter of data. Values reported here use the average fPM rate for each EGU.

[15] *Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards,* 80 FR 75178, 75201 (December 1, 2015).

[16] *National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Residual Risk and Technology Review,* 85 FR 45476, 45483 (July 28, 2020).

[17] *National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing Facilities Residual Risk and Technology Review,* 85 FR 42074, 42088 (July 13, 2020).

[18] *National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants,* 78 FR 10006, 10021 (February 12, 2013).

those estimates were substantially lower than estimates that the EPA has considered to be cost-effective in other technology reviews. Therefore, these commenters concluded that the EPA should strengthen the limit to at least 0.010 lb/MMBtu. These commenters also pointed to a 2023 report by Andover Technology Partners[19] that found that the cost to comply with an emission limit of 0.006 lb/MMBtu on a fleetwide basis was significantly less than the costs estimated by the EPA. Andover Technology Partners attributed this difference ''to the assumptions EPA made regarding the potential emission reductions from ESP upgrades, which result in a much higher estimate of baghouse retrofits in EPA's analysis for an emission rate of 0.006 lb/MMBtu.'' These commenters stated that meeting the lower emission limit of 0.006 lb/MMBtu is technologically feasible using currently available controls, and they urged the EPA to adopt this limit. They stated that although cost effectiveness is less relevant in the CAA section 112 context than for other CAA provisions, the $103,000 per ton of fPM and $209,000 per ton of filterable fine $PM_{2.5}$ estimates that the EPA calculated for the 0.006 lb/MMBtu limit were reasonable and comparable to past practice in technology reviews under CAA section 112(d)(6). They noted that the EPA has previously found a control measure that resulted in an inflation-adjusted cost of $185,000 per ton of $PM_{2.5}$ reduced to be cost-effective for the ferroalloys production source category[20] and proposed a limit for secondary lead smelting sources that cost an inflation-adjusted $114,000 per ton of fPM reduced.[21] They argued that, using the Andover Technology Partners cost estimates, the 0.006 lb/MMBtu limit has even better cost-effectiveness estimates at about $72,000 per ton of fPM reduced and $146,000 per ton of filterable $PM_{2.5}$ reduced. These commenters noted that the EPA also calculated cost effectiveness based on allowable emissions (*i.e.,* assuming emission reductions achieved if all evaluated EGUs emit at the maximum allowable amount of fPM, or 0.030 lb/MMBtu) at $1,610,000 per ton, showing that a limit of 0.006 lb/MMBtu allows far less pollution at low cost to the power sector. They concluded that all these metrics and approaches to considering costs show that a fPM limit of 0.006 lb/MMBtu would require cost-effective reductions and can be achieved at a reasonable cost that would not jeopardize the power sector's function.

Additionally, some commenters cited *Sierra Club* v. *Costle,* 657 F.2d 298, 330 (D.C. Cir. 1981), and said the case supports the EPA's discretion to weigh cost, energy, and environmental impacts, recognizing the Agency's authority to take these factors into account ''in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present.'' These commenters said that the EPA has the authority to require costs that are reasonable for the industry even if they are not reasonable for every facility. These commenters acknowledged that the EPA has discretion to consider cost effectiveness under CAA section 112(d)(2), citing *NRDC* v. *EPA,* 749 F.3d 1055, 1060–61 (D.C. Cir. 2014), but argued that the dollar-per-ton cost-effectiveness metric is less relevant under CAA section 112 than under other CAA provisions because the Agency is not charged with equitably distributing the costs of emission reductions through a uniform compliance strategy, as the EPA has done in its transport rules. The commenters concluded that the Agency should require maximum reductions of HAP emissions from each regulated source category and has no authority to balance cost effectiveness across industries.

Response: In this action, the EPA is acting under its authority in CAA section 112(d)(6) to ''review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards'' promulgated under CAA section 112. As the EPA explained in the 2023 Proposal, this technology review is separate and distinct from other standard-setting provisions under CAA section 112, such as establishing MACT floors, conducting the beyond-the-floor analysis, and reviewing residual risk.

Regarding the comments that the EPA underestimated costs to an extent that undermines the EPA's overall cost-effectiveness assumptions, the EPA disagrees that the Agency underestimated the typical costs of ESP rebuilds. The commenters provided cost examples from only two facilities to support their assertions regarding the costs of ESP rebuilds. The costs provided for one of those facilities, Labadie, were not the costs associated with an ESP rebuild, but instead were the costs associated with the full replacement of an ESP. The commenter stated that, ''Ameren retrofitted the entire ESP trains on two units in 2014/2015. On each of these units two of the three original existing ESPs had to be abandoned and one of the existing ESPs was retrofitted with new power supplies and flue gas flow modifications. A new state-of-the-art ESP was added to each unit to supplement the retrofitted ESPs.'' An ESP replacement is different from an ESP rebuild, and therefore the costs of an ESP replacement do not inform the costs of an ESP rebuild. The ESP rebuild cost provided for the other facility, Petersburg, was less than the EPA's final assumption regarding the typical cost of an ESP rebuild on a capacity-weighted average basis. Neither of these examples provided by the commenter demonstrate that the EPA underestimated costs. For these reasons, the EPA disagrees with these commenters. Additionally, the EPA disagrees with these commenters that the Agency must add a compliance margin in its cost assumptions. As described above, the Agency does not prescribe specifically how an EGU must be controlled or how it must be operated, and the choice of overcompliance is at the sole discretion of the owners and operators.

Generally, the EPA agrees with commenters that cost effectiveness, *i.e.,* the costs per unit of emissions reduction, is a metric that the EPA consistently considers, often alongside other cost metrics, in CAA section 112 rulemakings where it can consider costs, *e.g.,* beyond-the-floor analyses and technology reviews, and agrees with commenters who recognize that the Agency has discretion in how it considers statutory factors under CAA section 112(d)(6), including costs. *See e.g., Association of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667, 673–74 (D.C. Cir. 2013) (allowing that the EPA may consider costs in conducting technology reviews under CAA section 112(d)(6)); *see also Nat'l Ass'n for Surface Finishing* v. *EPA,* 795 F.3d 1, 11 (D.C. Cir. 2015). The EPA acknowledges that the cost-effectiveness values for these standards are higher than cost-effectiveness values that the EPA concluded were not cost-effective and weighed against implementing more stringent standards for some prior rules. The EPA disagrees, however, that there is any particular threshold that renders

---

[19] Assessment of Potential Revisions to the Mercury and Air Toxics Standards. Andover Technology Partners. June 15, 2023. Docket ID No. EPA–HQ–OAR–2018–0794. Also available at *https://www.andovertechnology.com/wp-content/uploads/2023/06/C_23_CAELP_Final.pdf.*

[20] *National Emission Standards for Hazardous Air Pollutants: Ferroalloys Production,* 80 FR 37381 (June 30, 2015).

[21] *National Emission Standards for Hazardous Air Pollutants: Secondary Lead Smelting,* 76 FR 29032 (May 19, 2011).

a rule cost-effective or not.[22] The EPA's prior findings about cost effectiveness in other rules were specific to those rulemakings and the industries at issue in those rules. As commenters have pointed out, in considering cost effectiveness, the EPA will often consider what estimates it has deemed cost-effective in prior rulemakings. However, the EPA routinely views cost effectiveness in light of other factors, such as other relevant costs metrics (*e.g.,* total costs, annual costs, and costs compared to revenues), impacts to the regulated industry, and industry-specific dynamics to determine whether there are ''developments in practices, processes, and control technologies'' that warrant updates to emissions standards pursuant to CAA section 112(d)(6). Some commenters, pointing to prior CAA section 112 rulemakings where the EPA chose not to adopt more stringent controls, mischaracterized cost effectiveness as the sole criterion in those decisions. These commenters omitted any discussion of other relevant factors from those rulemakings that, in addition to cost effectiveness, counseled the EPA against adopting more stringent standards. For example, in the 2014 Ferroalloys rulemaking that commenters cited to, the EPA rejected a potential control option due to questions about technical feasibility and significant economic impacts the option would create for the industry, including potential facility closures that would impact significant portions of industry production.[23] In contrast here, the controls at issue are technically feasible (they are used at facilities throughout the country) and will not have significant effects on the industry. Indeed, the EPA does not project that the final revisions to MATS will result in incremental changes in operational coal-fired capacity.

Similarly, in the other rulemakings these commenters pointed to, where the EPA found similar cost-effectiveness values to those that the EPA identified for the revised fPM standard here, there are distinct aspects of those rulemakings and industries that distinguish those prior actions from this rulemaking. In the 2015 Petroleum Refineries rulemaking, the EPA considered the cost effectiveness of developments at only two facilities to decide whether to deploy a standard across the much wider industry.[24] Here in contrast, the EPA is basing updates to fPM standards for coal-fired EGUs on developments across the majority of the industry and the performance of the fleet as a whole, which has demonstrated the achievability of a more stringent standard. Additionally, there are inherent differences between the power sector and other industries that similarly distinguish prior actions from this rulemaking. For example, because of the size of the power sector (314 coal-fired EGUs at 157 facilities), and because this source category is one of the largest stationary source emitters of Hg, arsenic, and HCl and is one of the largest regulated stationary source emitters of total HAP,[25] even considering that this rule affects only a fraction of the sector, the estimated HAP reductions in this final rule (8.3 tpy) are higher than those in the prior rulemakings cited by the commenters (as are the estimated PM reductions (2,537 tpy) used as a surrogate for non-Hg HAP metals). In contrast, in the 2020 Integrated Iron and Steel Manufacturing rulemaking, the source category covered included only 11 facilities, and the estimated reductions the EPA considered would have removed 3 tpy of HAP and 120 tpy of PM.[26] Likewise, in the 2013 Portland Cement rulemaking, the EPA determined not to pursue more stringent controls for the sector after finding the standard would only result in 138 tpy of nationwide PM reductions and that there was a high cost for such modest reductions.[27] Here, the EPA estimates significantly greater HAP emission reductions, and fPM emission reductions that are orders of magnitude greater than both prior rulemakings.[28]

There are also unique attributes of the power sector that the EPA finds support the finalization of revised standards for fPM and non-Hg HAP metals despite the relatively high cost-effectiveness values of this rulemaking as compared to other CAA section 112 rulemakings. As the EPA has demonstrated throughout this record, there are hundreds of EGUs regulated under MATS with well-performing control equipment that are already reporting emission rates below the revised standards, whereas only a handful of facilities with largely outdated or underperforming controls are emitting significantly more than their peers. That means that the communities located near these handful of facilities may experience exposure to higher levels of toxic metal emissions than communities located near similarly sized well-controlled plants. This is what the revised standards seek to remedy, and as discussed throughout this record, this goal is consistent with the EPA's authority under CAA section 112(d)(6) and the purpose of CAA section 112 more generally.

U.S. EGUs are a major source of HAP metals emissions including arsenic, beryllium, cadmium, chromium, cobalt, lead, nickel, manganese, and selenium. Some HAP metals emitted by U.S. EGUs are known to be persistent and bioaccumulative and others have the potential to cause cancer. Exposure to these HAP metals, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (*e.g.,* irritation of the lung, skin, and mucus membranes; decreased pulmonary function, pneumonia, or lung damage; detrimental effects on the central nervous system; damage to the kidneys; and alimentary effects such as nausea and vomiting). The emissions reductions projected under this final rule from the use of PM controls are expected to reduce exposure of individuals residing near these facilities to non-Hg HAP metals, including carcinogenic HAP.

EGUs projected to be impacted by the revised fPM standards represent a small fraction of the total number of the coal-fired EGUs (11 percent for the 0.010 lb/MMBtu fPM limit). In addition, many regulated facilities are electing to retire

---

[22] See *e.g., National Emissions Standards for Hazardous Air Pollutants: Ferroalloys Production,* 80 FR 37366, 37381 (June 30, 2015) (''[I]t is important to note that there is no bright line for determining acceptable cost effectiveness for HAP metals. Each rulemaking is different and various factors must be considered.'').

[23] *National Emission Standards for Hazardous Air Pollutants: Ferroalloys Production,* 79 FR 60238, 60273 (October 6, 2014).

[24] *Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards,* 80 FR 75178, 75201 (December 1, 2015).

[25] 2020 National Emissions Inventory (NEI) Data; *https://www.epa.gov/air-emissions-inventories/2020-national-emissions-inventory-nei-data.*

[26] *National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing Facilities Residual Risk and Technology Review,* 85 FR 42074, 42088 (July 13, 2020).

[27] *National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants,* 78 FR 10006, 10020–10021 (February 12, 2013).

[28] In addition, while commenters are correct that the EPA determined not to adopt more stringent controls under the iron ore processing technology review, the aspects of the rulemaking that the commenters cite to concerned whether additional controls were necessary to provide an ample margin of safety under a residual risk review. In that instance, the EPA determined not to implement more stringent standards under the risk review based on the installation of wet ESPs in addition to wet scrubbers, based on the EPA's determination that such improvements were not necessary to provide an ample margin of safety to protect public health. See *National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Residual Risk and Technology Review,* 84 FR 45476, 45483 (July 28, 2020).

due to factors independent of the EPA's regulations, and the EPA typically has more information on plant retirements for this sector than other sectors regulated under CAA section 112. Both of these factors contribute to relatively higher cost-effectiveness estimates in this rulemaking as compared to other sectors where the EPA is not able to account for facility retirements and factor in shorter amortization periods for the price of controls.

While some commenters stated that meeting an even lower emission limit of 0.006 lb/MMBtu is technologically feasible using currently available controls, the Agency declines to finalize this limit primarily due to the technological limitations of PM CEMS at this lower emission limit (as discussed in more detail in sections IV.C.2. and IV.D.2. below). Additionally, the EPA considered the higher costs associated with a more stringent standard as compared to the final standard presented in section IV.D.1.

Finally, as mentioned in the Response to Comments document, the EPA finds that use of PM CEMS, which provide continuous feedback with respect to fPM variability, in lieu of quarterly fPM emissions testing, will render moot the commenter's suggestion that margin of compliance has not been taken into account.

Comment: Some commenters argued that the low residual risks the EPA found in its review of the 2020 Residual Risk Review obviate the need for the EPA to revise the standards under the separate technology review, and that residual risk should be a relevant aspect of the EPA's technology review of coal- and oil-fired EGUs. These commenters argued that it is arbitrary and capricious for the EPA to impose high costs on facilities, which they claimed will only result in marginal emission reductions, when the EPA determined there is not an unreasonable risk to the environment or public health.

Other commenters agreed with the EPA's ''two-pronged'' interpretation that CAA section 112(d)(6) provides authorities to the EPA that are distinct from the EPA's risk-based authorities under CAA section 112(f)(2). These commenters said that if the criteria under CAA section 112(d)(6) are met, the EPA must update the standards to reflect new developments independent of the risk assessment process under CAA section 112(f)(2). They said the technology-based review conducted under CAA section 112(d)(6) need not account for any information learned during the residual risk review under CAA section 112(f)(2) unless that information pertains to statutory factors under CAA section 112(d)(6), such as costs. They concluded that CAA section 112(d)(6) requires the EPA to promulgate the maximum HAP reductions possible where achievable at reasonable cost and is separate from the EPA's residual risk analysis.

Response: The EPA has an independent statutory authority and obligation to conduct the technology review separate from the EPA's authority to conduct a residual risk review, and the Agency agrees with commenters that recognized that the EPA is not required to account for information obtained during a residual risk review in conducting a technology review. The EPA's finding that there is an ample margin of safety under the residual risk review in no way interferes with the EPA's obligation to require more stringent standards under the technology review where developments warrant such standards. The D.C. Circuit has recognized the CAA section 112(d)(6) technology review and 112(f)(2) residual review are ''distinct, parallel analyses'' that the EPA undertakes ''[s]eparately.'' *Nat'l Ass'n for Surface Finishing* v. *EPA,* 795 F.3d 1, 5 (D.C. Cir. 2015). In other recent residual risk and technology reviews, the EPA determined additional controls were warranted under technology reviews pursuant to CAA section 112(d)(6) although the Agency determined additional standards were not necessary to maintain an ample margin of safety under CAA section 112(f)(2).[29] The EPA has also made clear that the Agency ''disagree[s] with the view that a determination under CAA section 112(f) of an ample margin of safety and no adverse environmental effects alone will, in all cases, cause us to determine that a revision is not necessary under CAA section 112(d)(6).''[30] While the EPA has considered risks as a factor in some previous technology reviews,[31] that does not compel the Agency to do so in this rulemaking. Indeed, in other instances, the EPA has adopted the same standards under both CAA sections 112(f)(2) and 112(d)(6) based on independent rationales where necessary to provide an ample margin of safety and because it is technically appropriate and necessary to do so, emphasizing the independent authority of the two statutory provisions.[32]

The language and structure of CAA section 112, along with its legislative history, further underscores the independent nature of these two provisions.[33] While the EPA is only required to undertake the risk review once (8 years after promulgation of the original MACT standards), it is required to undertake the technology review multiple times (at least every 8 years after promulgation of the original MACT standard). That Congress charged the EPA to ensure an ample margin of safety through the risk review, yet still required the technology review to be conducted on a periodic basis, demonstrates that Congress anticipated that the EPA would strengthen standards based on technological developments even after it had concluded there was an ample margin of safety. CAA section 112's overarching charge to the EPA to ''require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions)'' further demonstrates that Congress sought to minimize the emission of hazardous air pollution wherever feasible independent of a finding of risk. Moreover, as discussed *supra,* in enacting the 1990 CAA Amendments, Congress purposefully replaced the previous risk-based approach to establishing standards for HAP with a technology-driven approach. This technology-driven

---

[29] See, *e.g., National Emission Standards for Hazardous Air Pollutants: Refractory Products Manufacturing Residual Risk and Technology Review,* 86 FR 66045 (November 19, 2021); *National Emission Standards for Hazardous Air Pollutants: Site Remediation Residual Risk and Technology Review,* 85 FR 41680 (July 10, 2020); *National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) Residual Risk and Technology Review,* 85 FR 40740, 40745 (July 7, 2020); *National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology Standards Residual Risk and Technology Review for Ethylene Production,* 85 FR 40386, 40389 (July 6, 2020); *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills,* 82 FR 47328 (October 11, 2017); *National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology Standards; and Manufacture of Amino/Phenolic Resins,* 79 FR 60898, 60901 (October 8, 2014).

[30] *National Emission Standards for Hazardous Air Pollutant Emissions: Group I Polymers and Resins; Marine Tank Vessel Loading Operations; Pharmaceuticals Production; and the Printing and Publishing Industry,* 76 FR 22566, 22577 (April 21, 2011).

[31] See, *e.g., National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry,* 71 FR 76603, 76606 (December 21, 2006); *see also Proposed Rules: National Emission Standards for Halogenated Solvent Cleaning,* 73 FR 62384, 62404 (October 20, 2008).

[32] *National Emissions Standards for Hazardous Air Pollutants: Secondary Lead Smelting,* 77 FR 556, 564 (January 5, 2012).

[33] See section II.A.2. above for further discussion of the statutory structure and legislative history of CAA section 112.

approach recognizes the ability for the EPA to achieve substantial reductions in HAP based on technological improvements without the inherent difficulty in quantifying risk associated with HAP emission exposure given the complexities of the pathways through which HAP cause harm and insufficient availability of data to quantify their effects discussed in section II.B.2. Independent of risks, it would be inconsistent with the text, structure, and legislative history for the EPA to conclude that Congress intended the statute's technology-based approach to be sidelined after the EPA had concluded the risk review.

Comment: Some commenters expressed concern that some portion of affected units could simply retire instead of coming into compliance with new requirements, potentially occurring before new generation could be built to replace the lost generation. During this period, a lack of dispatchable generation could significantly increase the likelihood of outages, particularly during periods of severe weather. In addition, some commenters argued that revising the fPM limit was unnecessary as there is a continuing downward trend in HAP emissions from early retirements of coal-fired EGUs, whereas accelerating this trend could have potential adverse effects on reliability. Some commenters also stated that as more capacity and generation is shifted away from coal-fired EGUs due to the Inflation Reduction Act (IRA) and other regulatory and economic factors, the total annual fPM and HAP emissions from industry will decline, regardless of whether the fPM limit is made more stringent.

Response: The EPA disagrees that this rule would threaten resource adequacy or otherwise degrade electric system reliability. Commenters provided no credible information supporting the argument that this final rule would result in a significant number of retirements or a larger amount of capacity needing controls. The Agency estimates that this rule will require additional fPM control at less than 12 GW of operable capacity in 2028, which is about 11 percent of the total coal-fired EGU capacity projected to operate in that year. The units requiring additional fPM controls are projected to generate less than 1.5 percent of total generation in 2028. Moreover, the EPA does not project that any EGUs will retire in response to the standards promulgated in this final rule. Because the EPA projects no incremental changes in existing operational capacity to occur in response to the final rule, the EPA does not anticipate this rule will have any implications for resource adequacy.

Nevertheless, it is possible that some EGU owners may conclude that retiring a particular EGU and replacing it with new capacity is a more economic option from the perspective of the unit's customers and/or owners than making investments in new emissions controls at the unit. The EPA understands that before implementing such a retirement decision, the unit's owner will follow the processes put in place by the relevant regional transmission organization (RTO), balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of additional revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place. No commenter stated that this rule would somehow authorize any EGU owner to unilaterally retire a unit without following these processes, yet some commenters nevertheless assume without any rationale that is how multiple EGU owners would proceed, in violation of their obligations to RTOs, balancing authorities, or state regulators relating to the provision of reliable electric service.

In addition, the Agency has granted the maximum time allowed for compliance under CAA section 112(i)(3) of 3 years, and individual facilities may seek, if warranted, an additional 1-year extension of the compliance date from their permitting authority pursuant to CAA section 112(i)(3)(B). The construction of any additional pollution control technology that EGUs might install for compliance with this rule can be completed within this time and will not require significant outages beyond what is regularly scheduled for typical maintenance. Facilities may also obtain, if warranted, an emergency order from the Department of Energy pursuant to section 202(c) of the Federal Power Act (16 U.S.C. 824a(c)) that would allow the facility to temporarily operate notwithstanding environmental limits when the Secretary of Energy determines doing so is necessary to address a shortage of electric energy or other electric reliability emergency.

Further, despite the comments asserting concerns over electric system reliability, no commenter cited a single instance where implementation of an EPA program caused an adverse reliability impact. Indeed, similar claims made in the context of the EPA's prior CAA rulemakings have not been borne out in reality. For example, in the stay litigation over the Cross-State Air Pollution Rule (CSAPR), claims were made that allowing the rule to go into effect would compromise reliability. Yet in the 2012 ozone season starting just over 4 months after the rule was stayed, EGUs covered by CSAPR collectively emitted below the overall program budgets that the rule would have imposed in that year if the rule had been allowed to take effect, with most individual states emitting below their respective state budgets. Similarly, in the litigation over the 2015 Clean Power Plan, assertions that the rule would threaten electric system reliability were made by some utilities or their representatives, yet even though the Supreme Court stayed the rule in 2016, the industry achieved the rule's emission reduction targets years ahead of schedule without the rule ever going into effect. *See West Virginia* v. *EPA,* 142 S. Ct. 2587, 2638 (2022) (Kagan, J., dissenting) (''[T]he industry didn't fall short of the [Clean Power] Plan's goal; rather, the industry exceeded that target, all on its own . . . . At the time of the repeal . . . 'there [was] likely to be no difference between a world where the [Clean Power Plan was] implemented and one where it [was] not.' '') (quoting 84 FR 32561). In other words, the claims that these rules would have had adverse reliability impacts proved to be groundless.

The EPA notes that similar concerns regarding reliability were raised about the 2012 MATS Final Rule—a rule that projected the need for significantly greater installation of controls and other capital investments than this current revision.[34] As with the current rule, the flexibility of permitting authorities to allow a fourth year for compliance was available in a broad range of situations, and in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides flexibilities to bring sources into compliance while maintaining reliability. We have seen no evidence in the last decade to suggest

---

[34] The EPA projected that the 2012 MATS Final Rule would drive the installation of an additional 20 GW of dry FGD (dry scrubbers), 44 GW of DSI, 99 GW of additional ACI, 102 GW of additional FFs, 63 GW of scrubber upgrades, and 34 GW of ESP upgrades. While a subsequent analysis found that the industry ultimately installed fewer controls than was projected, the control installations that occurred following the promulgation of the 2012 MATS Final Rule were still significantly greater than the installations that are estimated to occur as a result of this final rule (where, for example, the EPA estimates that less than 2 GW of capacity would install FF technology for compliance).

that the implementation of MATS caused power sector adequacy and reliability problems, and only a handful of sources obtained administrative orders under the enforcement policy issued with MATS to provide relief to reliability critical units that could not comply with the rule by 2016.

Comment: Commenters suggested that the EPA use its authority to create subcategories of affected facilities that elect to permanently retire by the compliance date as the Agency has taken in similar proposed rulemakings affecting coal- and oil-fired EGUs. Commenters stated the EPA should subcategorize those sources that have adopted enforceable retirement dates and not subject those sources to any final rule requirements. They indicated that the EPA is fully authorized to subcategorize these units under CAA section 112(d)(1). Commenters asked that the EPA consider other simultaneous rulemakings, such as the proposed Greenhouse Gas Standards and Guidelines for Fossil Fuel Power Plants,[35] where the EPA proposed that EGUs that elect to shut down by January 1, 2032, must maintain their recent historical carbon dioxide (CO_2) emission rate via routine maintenance and operating procedures (*i.e.,* no degradation of performance). Commenters also referenced the retirement date of December 31, 2032, in the EPA Office of Water's proposed Effluent Limitation Guidelines.[36]

Commenters claimed that creating a subcategory for units facing near-term retirements that harmonizes the retirement dates with other rulemakings would greatly assist companies with moving forward on retirement plans without running the risk of being forced to retire early, which could create reliability concerns or, in the alternative, forced to deliberate whether to install controls and delaying retirement to recoup investments in the controls. Commenters also suggested that EGUs with limited continued operation be allowed to continue to perform quarterly stack testing to demonstrate compliance with the fPM limitations (rather than having to install PM CEMS). Commenters suggested that imposing different standards on these subcategories should continue the status quo for these units until retirement. Commenters claimed that it would make no sense for the EPA to require an EGU slated to retire in the near term to expend substantial resources on controls in the interim since these sources are very unlikely to find it viable to construct significant control upgrades for a revised standard that would become effective in mid-2027, only 5 years before the unit's permanent retirement. Commenters further noted if the EPA does not establish such a subcategory or take other action to ensure these units are not negatively impacted by the rulemaking, the retirement of some units could be accelerated due to the costs of installing a PM CEMS and the need to rebuild or upgrade an existing ESP or install a FF to supplement an existing ESP. Commenters stated that the EPA cannot ignore the need for a coordinated retirement of thermal generating capacity while new generation sources come online to avoid detrimental impacts to grid reliability.

Commenters suggested that if the EPA decides to proceed with finalizing the revised standards in the 2023 Proposal, the Agency should create a subcategory for coal-fired EGUs that elect by the compliance date of the revised standards (*i.e.,* mid-2027) to retire the units by December 31, 2032, or January 1, 2032, if the EPA prefers to tie the 2023 Proposal to the proposed Emission Guidelines instead of the Effluent Limitation Guidelines, and maintain the current MATS standards for this subcategory of units. Commenters requested that the EPA coordinate the required retirement date for the 2023 Proposal with other rules so that all retirement dates align. Commenters reiterated that the EPA has multiple authorities with overlapping statutory timelines that affect commenters' plans regarding the orderly retirement of coal-fired EGUs and their ability to continue the industry's clean energy transformation while providing the reliability and affordability that their customers demand. Commenters suggested that EGUs that plan to retire by 2032 should have the opportunity to seek a waiver from PM CEMS installation altogether and continue quarterly stack testing during the remaining life of the unit. They also suggested that if a unit does not retire by the specified date, it should be required to immediately cease operation or meet the standards of the rule. Commenters stated that under this recommendation an EGU's failure to comply would then be a violation of the 2023 Proposal's final rule subject to enforcement.

Response: In response to commenters' concerns, the EPA evaluated the feasibility of creating a subcategory for facilities with near-term retirements but disagrees with commenters that such a subcategory is appropriate for this rulemaking. In particular, the EPA found that, based on its own assessment and that of commenters, only a few facilities would likely be eligible for a near-term retirement subcategory and that it would not significantly reduce the costs of the revised standards. According to the EPA's assessment, 67 of the 296 EGUs assessed[37] have announced retirements between 2029 and 2032—less than one-quarter of the fleet—and all but three of those EGUs (at two facilities) have already demonstrated the ability to comply with the 0.010 lb/MMBtu fPM standard on average. Additionally, these three EGUs already use PM CEMS to demonstrate compliance, therefore the comment requesting a waiver of PM CEMS installations for EGUs with near-term retirements is not relevant. Because the EPA's analysis led the Agency to conclude that there would be little utility to a near-term retirement subcategory and it would not change the costs of the rule in a meaningful way, the EPA determined not to create a retirement subcategory for the fPM standard. In addition, the EPA notes that allowing units to operate without the best performing controls for an additional number of years would lead to higher levels of non-Hg HAP metals emissions and continued exposure to those emissions in the communities around these units during that timeframe. Regarding a fPM compliance requirement subcategory for EGUs with near-term retirements, the Agency estimates 26 of 67 EGUs are already using PM CEMS for compliance demonstration and finds that the costs to install PM CEMS for facilities with near-term retirements are reasonable. The Agency finds that the transparency provided by PM CEMS and the increased ability to quickly detect and correct potential control or operational problems using PM CEMS furthers Congress's goal to ensure that emission reductions are consistently maintained and makes PM CEMS the best choice for this rule's compliance monitoring for all EGUs.

2. Comments on the Proposed Changes to the Compliance Demonstration Options

Comment: The Agency received both supportive and opposing comments requiring the use of PM CEMS for compliance demonstration. Supportive commenters stated the EPA must require the use of PM CEMS to monitor their emissions of non-Hg HAP metals

---

[35] 88 FR 33245 (May 23, 2023).

[36] 88 FR 18824, 18837 (March 29, 2023).

[37] In this final rule, the EPA reviewed fPM compliance data for 296 coal-fired EGUs expected to be operational on January 1, 2029. This review is explained in detail in the 2024 Technical Memo.

as PM CEMS are now more widely deployed than when MATS was first promulgated, and experience with PM CEMS has enabled operators to more promptly detect and correct problems with pollution controls as compared to other monitoring and testing options allowed under MATS (*i.e.,* periodic stack testing and parametric monitoring for PM), thereby lowering HAP emissions. They said that the fact that PM CEMS have been used to demonstrate compliance in a majority of units in the eight best performing deciles[38] provides strong evidence that PM CEMS can be used effectively to measure low levels of PM emissions.

Opposing commenters urged the EPA to retain all current options for demonstrating compliance with non-Hg HAP metal standards, including quarterly PM and metals testing, LEE, and PM CPMS. These commenters said removing these compliance flexibility options goes beyond the scope of the RTR and does not address why the reasons these options were originally included in MATS are no longer valid. Commenters said they have previously raised concerns about PM CEMS that the EPA has avoided by stating that CEMS are not the only compliance method for PM. They stated that previously, the EPA has determined these compliance methods were both adequate and frequent enough to demonstrate compliance.

Response: The Agency disagrees with commenters who suggests that the rule should retain all previous options for demonstrating compliance with either the individual metals, total metals, or fPM limits. Congress intended for CAA section 112 to achieve significant reductions of HAP, and the EPA agrees with other commenters that the use of CEMS in general and PM CEMS in particular enables owners or operators to detect and quickly correct control device or process issues in many cases before the issues become compliance problems. Consistent with the discussion contained in the 2023 Proposal (88 FR 24872), the Agency finds the transparency and ability to quickly detect and correct potential control or operational problems furthers Congress's goal to ensure that emission reductions are consistently maintained and makes PM CEMS the best choice for this rule's compliance monitoring.

Comment: Some commenters objected to the EPA's proposal to require the use of PM CEMS for purposes of demonstrating compliance with the revised fPM standard, stating that the requirements of Performance Specification 11 of 40 CFR part 60, appendix B (PS–11) will become extremely hard to satisfy at the low emission limits proposed. For PS–11, relative correlation audit (RCA), and relative response audit (RRA), the tolerance interval and confidence interval requirements are expressed in terms of the emission standard that applies to the source. The commenters reviewed test data from operating units and found significantly higher PS–11 failure (>80 percent), RCA failure (>80 percent), and RRA failure (60 percent) rates at the more stringent proposed emission limits. They stated that the cost, complexity, and failure rate of equipment calibration remains one of the biggest challenges with the use of PM CEMS and therefore other compliance demonstration methods should be retained. Commenters also noted that repeated tests due to failure could result in higher total emissions from the units.

Response: The Agency is aware of concerns by some commenters that PM CEMS currently correlated for the 0.030 lb/MMBtu fPM emission limit may experience difficulties should re-correlation be necessary; and those concerns are also ascribed to yet-to-be installed PM CEMS. In response to those concerns, the Agency has shifted the basis of correlation testing from requiring only the collection of a minimum volume per run to also allowing the collection of a minimum mass per run and has adjusted the QA criterion otherwise associated with the new emission limit. These changes will ease the transition for coal- and oil-fired EGUs using only PM CEMS for compliance demonstration purposes. The first change, allowing the facility to choose either the collection of a minimum mass per run or a minimum volume per run, should reduce high-level correlation testing duration, addressing other concerns about extended runtimes with degraded emissions control or increased emissions, and should reduce correlation testing costs. The second change, adjusting the QA criteria, is consistent with other approaches the Agency has used when lower ranges of instrumentation or methods are employed. For example, in section 13.2 of Performance Specification 2 (40 CFR part 60, appendix B) the QA criteria for the relative accuracy test audit for SO_2 and Nitrogen Oxide CEMS are relaxed as the emission limit decreases. This is accomplished at lower emissions by allowing a larger criterion or by modifying the calculation and allowing a less stringent number in the denominator. With these changes to the QA criteria and correlation procedures, the EPA believes EGUs will be able to use PM CEMS to demonstrate compliance at the revised level of the fPM standard.

Comment: Some commenters asserted that if the EPA finalizes the requirement to demonstrate compliance using PM CEMS, EGUs will not be able to comply with a lower fPM limit on a continuous basis and that accompanying a lower limit with more restrictive monitoring requirements adds to the regulatory burden of affected sources and permitting authorities.

Response: The EPA disagrees with commenters' claim that that EGUs will not be able to demonstrate compliance continuously with a fPM limit of 0.010 lb/MMBtu. The EPA believes that CEMS in general and PM CEMS in particular enable owners and operators to detect and quickly correct control device or process issues in many cases before the issues become compliance problems. Contrary to the commenter's assertion that EGUs will not be able to comply with a lower fPM limit on a continuous basis, as mentioned in the June 2023 Andover Technology Partners analysis,[39] over 80 percent of EGUs using PM CEMS for compliance purposes have already been able to achieve and are reporting and certifying consistent achievement of fPM rates below 0.010 lb/MMBtu.[40] The EPA is unaware of any additional burden experienced by those EGU owners or operators or their regulatory authorities with regard to PM CEMS use at these lower emission levels, and does not expect additional burden to be placed on EGU owners or operators with regard to PM CEMS from application of the revised emission limit. However, this final rule incorporates approaches, such as switching from a minimum sample volume per run to collection of a

---

[38] Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants. Andover Technology Partners. August 19, 2021. Document ID No. EPA–HQ–OAR–2018–0794–4583.

[39] Assessment of Potential Revisions to the Mercury and Air Toxics Standards. Andover Technology Partners. June 15, 2023. Docket ID No. EPA–HQ–OAR–2018–0794. June 2023. Also available at *https://www.andovertechnology.com/wp-content/uploads/2023/06/C_23_CAELP_Final.pdf.*

[40] See for example the PM CEMS Thirty Boiler Operating Day Rolling Average Reports for Duke's Roxboro Steam Electric Plant in North Carolina and at Minnesota Power's Boswell Energy Center in Minnesota. These reports and those from other EGUs reporting emission levels at or lower than 0.010 lb/MMBtu are available electronically by searching in the EPA's Web Factor Information Retrieval System (WebFIRE) Report Search and Retrieval portion of the Agency's WebFIRE internet website at *https://cfpub.epa.gov/webfire/reports/esearch.cfm.*

minimum mass sample or mass volume per run and adjusting the PM CEMS QA acceptability criteria, to reduce the challenges with using PM CEMS. Moreover, the 30-boiler-operating-day averaging period of the limit provides flexibility for owners and operators to account for equipment malfunctions and other issues. Consistent with the discussion in the 2023 Proposal,[41] the Agency finds that PM CEMS are the best choice for this rule's compliance monitoring as they provide increased emissions transparency, ability for EGU owner/operators to quickly detect and correct potential control or operational problems, and greater assurance of continuous compliance. While PM CEMS can produce values at lower levels provided correlations are developed appropriately, the Agency established the final fPM limit of 0.010 lb/MMBtu after considering factors such as run times necessary to develop correlations, potential random error effects, and costs.

Comment: Commenters stated that the EPA's cost estimates contradict the Agency's suggestion that the use of PM CEMS is a more cost-effective monitoring approach than quarterly testing, especially for units that qualify as LEE. They said that the EPA used estimates from the Institute of Clean Air Companies (ICAC) or Envea/Altech which do not include numerous costs associated with PM CEMS that make them not cost-effective, such as the cost of intermittent stack testing associated with the PS–11 correlations and the ongoing costs of RCAs and RRA, which are a large part of the costs associated with PM CEMS and would rise substantially in conjunction with the proposed new PM limits. The commenters said that the ICAC estimated range of PM CEMS installation costs are particularly understated and outdated and should be ignored by the Agency. They said that the EPA estimates may also understate PM CEMS cost by assuming the most commonly used light scattering based PM CEMS will be used for all applications. The commenters said that while more expensive, a significant number of beta gauge PM CEMS are used for MATS compliance, especially where PM spiking is used for PS–11 correlation and RCA testing and that this higher degree of accuracy from beta gauge PM CEMS may be needed for sources without a margin of compliance under the new, more stringent emission limit.

Response: The EPA disagrees with the commenters' suggestion that the Agency is required to select the most cost-effective approach for compliance monitoring. Rather, the Agency selects the approach that best provides assurance that emission limits are met. PM CEMS annual costs represent a very small fraction of a typical coal-fired EGU's operating costs and revenues. As described in the *Ratio of Revised Estimated Non-Beta Gauge PM CEMS EUAC to 2022 Average Coal-Fired EGU Gross Profit* memorandum, available in the docket, if all coal-fired EGUs were to purchase and install new PM CEMS, the Equivalent Uniform Annual Cost (EUAC) would represent less than four hundredths of a percent of the average annual operating expenses from coal-fired EGUs.

Further, as described in the *Revised Estimated Non-Beta Gauge PM CEMS and Filterable PM Testing Costs* technical memorandum, available in the rulemaking docket, the EPA calculated average costs for PM CEMS and quarterly testing from values submitted by commenters in response to the proposal's solicitation, which are discussed in section IV.D. of the preamble. Based on the commenters' suggestions, these revised costs include the costs of intermittent stack testing associated with the PS–11 correlations and ongoing costs of RCAs and RRAs. While the average EUAC for PM CEMS exceeds the average annual cost of quarterly stack emission testing, the cost for PM CEMS does not include important additional benefits associated with providing continuous emissions data to EGU owners or operators, regulators, nearby community members, or the general public. As a reminder, the EPA is not obligated to choose the most inexpensive approach for compliance demonstrations, particularly when all benefits are not monetized, even though costs can be an important consideration. Consistent with the discussion contained in the 2023 Proposal at 88 FR 24872, the Agency finds the increased transparency of EGU fPM emissions and the ability to quickly detect and correct potential control or operational problems, along with greater assurance of continuous compliance makes PM CEMS the best choice for this rule's compliance monitoring.

The Agency acknowledges the commenters' suggestions that EGU owners or operators may find that using beta gauge PM CEMS is most appropriate for the lower fPM emission limit in the rule; such suggestions are consistent with the Agency's view, as expressed in 88 FR 24872. However, the Agency believes other approaches, including spiking, can also ease correlation testing for PM CEMS. Moreover, the Agency anticipates that the new fPM limit will increase demand for, and perhaps spur increased production of, beta gauge PM CEMS.

D. What is the rationale for our final approach and decisions for the filterable PM (as a surrogate for non-Hg HAP metals) standard and compliance demonstration options?

The EPA is finalizing a lower fPM emission standard of 0.010 lb/MMBtu for coal-fired EGUs, as a surrogate for non-Hg HAP metals, and the use of PM CEMS for compliance demonstration purposes for coal- and oil-fired EGUs (with the exception of limited-use liquid oil-fired EGUs) based on developments in the performance of sources within the category since the EPA finalized MATS and the advantages conferred by using CEMS for compliance. As described in the 2023 Proposal, non-Hg HAP metals are predominately a component of fPM, and control of fPM results in concomitant reduction of non-Hg HAP metals (with the exception of Se, which may be present in the filterable fraction or in the condensable fraction as the acid gas, SeO_2). The EPA observes that since MATS was finalized, the vast majority of covered units have significantly outperformed the standard, with a small number of units lagging behind and emitting significantly higher levels of these HAP in communities surrounding those units. The EPA deems it appropriate to require these lagging units to bring their pollutant control performance up to that of their peers. Moreover, the EPA concludes that requiring use of PM CEMS for compliance yields manifold benefits, including increased emissions transparency and data availability for owners and operators and for nearby communities.

The EPA's conclusions with regard to the fPM standard and requirement to use PM CEMS for compliance demonstration are closely related, both in terms of CAA section 112(d)(6)'s direction for the EPA to reduce HAP emissions based on developments in practices, processes, and control technologies, and in terms of technical compatibility.[42] The EPA finds that the manifold benefits of PM CEMS render it appropriate to promulgate an updated fPM emission standard as a surrogate for non-Hg HAP metals for which PM CEMS can be used to monitor

---

[41] See 88 FR 24872.

[42] As noted in section III.A. above, there are nonetheless independent reasons for adopting both the revision to the fPM standard and the PM CEMS compliance demonstration requirement and each of these changes would continue to be workable without the other in effect, such that the EPA finds the two revisions are severable from each other.

compliance. However, as the fPM limit is lowered, operators may encounter difficulties establishing and maintaining existing correlations for the PM CEMS and may therefore be unable to provide accurate values necessary for compliance. The EPA has determined, based on comments and on the additional analysis described below, that the lowest possible fPM limit considering these challenges at this time is 0.010 lb/MMBtu with adjusted QA criteria. Therefore, the EPA determined that this two-pronged approach—requiring PM CEMS in addition to a lower fPM limit—is the most stringent option that balances the benefits of using PM CEMS with the emission reductions associated with the tightened fPM emission standard. Further, the EPA finds that the more stringent limit of 0.006 lb/MMBtu fPM cannot be adequately monitored with PM CEMS at this time, because the random error component of measurement uncertainty from correlation stack testing is too large and the QA criteria passing rate for PM CEMS is too small to provide accurate (and therefore enforceable) compliance values. Below, we further describe our rationale for each change.

1. Rationale for the Final Filterable PM Emission Standard

In the 2023 Proposal, the Agency proposed a lower fPM emission standard for coal-fired EGUs as a surrogate for non-Hg HAP metals based on developments in practices, processes, and control technologies pursuant to CAA section 112(d)(6), including the EPA's assessment of the differing performance of sources within the category and updated information about the cost of controls. As described in the 2023 Proposal, non-Hg HAP metals are predominately a component of fPM, and control of fPM results in reduction of non-Hg HAP metals (with the exception of Se, which may be present in the filterable fraction or in the condensable fraction as the acid gas, SeO_2).

In conducting this technology review, the EPA found important developments that informed its proposal. First, from reviewing historical information contained in WebFIRE,[43] the EPA observed that most EGUs were reporting fPM emission rates well below the 0.030 lb/MMBtu standard. The fleet was achieving these performance levels at lower costs than estimated during promulgation of the 2012 MATS Final Rule. Second, there are technical developments and improvements in PM control technology since the 2012 MATS Final Rule that informed the 2023 Proposal.[44] For example, while ESP technology has not undergone fundamental changes since 2011, industry has learned and adopted "best practices" associated with monitoring ESP operation more carefully since the 2012 MATS Final Rule. For FFs, more durable materials have been developed since the 2012 MATS Final Rule, which are less likely to fail due to chemical, thermal, or abrasion failure and create risks of high PM emissions. For instance, fiberglass (once the most widely used material) has largely been replaced by more reliable and easier to clean materials, which are more costly. Coated fabrics, such as Teflon or P84 felt, also clean easier than other fabrics, which can result in less frequent cleaning, reducing the wear that could damage filter bags and reduce the effectiveness of PM capture.

To examine potential revisions, the EPA evaluated fPM compliance data for the coal-fired fleet and evaluated the control efficiency and costs of PM controls to achieve a lower fPM standard. Based on comments received on the 2023 Proposal, the EPA reviewed additional fPM compliance data for 62 EGUs at 33 facilities (see 2024 Technical Memo and attachments for detailed information). The review of additional fPM compliance data showed that more EGUs had previously demonstrated an ability to meet a lower fPM rate, as shown in figure 4 of the 2024 Technical Memo. Compared to the 2023 Proposal where 91 percent of existing capacity demonstrated an ability to meet 0.010 lb/MMBtu, the updated analysis showed that 93 percent are demonstrating the ability to meet 0.010 lb/MMBtu with existing controls. The EPA received comments on the cost assumptions for upgrading PM controls and found that the costs estimated at proposal were not only too high, but that the cost effectiveness of PM upgrades was also underestimated (*i.e.,* the standard is more cost-effective than the EPA believed at proposal).

The EPA is finalizing the fPM emission limit of 0.010 lb/MMBtu with adjusted QA criteria, based on developments since 2012, for the reasons described in this final rule and in the 2023 Proposal as the lowest achievable fPM limit that allows for the use of PM CEMS for compliance demonstration purposes. First, this level of control ensures that the highest emitters bring their performance to a level where the vast majority of the fleet is already performing. For example, as described above, the majority of the existing coal-fired fleet subject to this final rule has previously demonstrated an ability to comply with the lower 0.010 lb/MMBtu fPM limit at least 99 percent of the time during one quarter, in addition to meeting the lower fPM limit on average across all quarters assessed. The Agency estimates that only 33 EGUs are currently operating above this revised limit. Compared to some of the best performing EGUs, the 33 EGUs requiring additional PM control upgrades or maintenance are more likely to have an ESP instead of a FF and to demonstrate compliance using intermittent stack testing. In addition, most of these EGUs have operated at a higher level of utilization than the coal-fired fleet on average.

Second, as discussed in section II.A.2. above, Congress updated CAA section 112 in the 1990 Clean Air Act Amendments to achieve significant reductions in HAP emissions, which it recognized are particularly harmful pollutants, and implemented a regime under which Congress directed the EPA to make swift and substantial reductions to HAP based upon the most stringent standards technology could achieve. This is evidenced by Congress's charge to the EPA to "require the maximum degree of reduction in emissions of hazardous air pollutants (including a prohibition on such emissions)," that is achievable accounting for "the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements. . . ." CAA section 112(d)(2). Further, by creating separate and distinct requirements for the EPA to consider updates to CAA section 112 pursuant to both technology review under CAA section 112(d)(6) and residual risk review under CAA section 112(f)(2), Congress anticipated that the EPA would strengthen standards pursuant to technology reviews "as necessary (taking into account developments in practices, processes, and control technologies)," CAA section 112(d)(6), even after the EPA concluded there was an ample margin of safety based on the risks that the EPA can quantify.[45] As the EPA explained in the

---

[43] WebFIRE includes data submitted to the EPA from the Electronic Reporting Tool (ERT) and is searchable at *https://cfpub.epa.gov/webfire/reports/esearch.cfm.*

[44] Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants. Andover Technology Partners. August 19, 2021. Document ID No. EPA–HQ–OAR–2018–0794–4583.

[45] EPA's CAA section 112(f)(2) quantitative risk assessments evaluate cancer risk associated with a lifetime of exposure to HAP emissions from each source in the source category, the potential for HAP exposure to cause adverse chronic (or long-term) noncancer health effects, and the potential for HAP

proposal, the EPA does consider costs, technical feasibility, and other factors when evaluating whether it is necessary to revise existing emission standards under CAA section 112(d)(6) to ensure the standards ''require the maximum degree of emissions reductions . . . achievable.'' CAA section 112(d)(2). The text, structure, and history of this provision demonstrate Congress's direction to the EPA to require reduction in HAP where technology is available to do so and the EPA accounts for the other statutory factors.

Accordingly, the EPA finds that bringing this small number of units to the performance levels of the rest of the fleet serves Congress's mandate to the EPA in CAA section 112(d)(6) to continually consider developments ''that create opportunities to do even better.'' *See LEAN,* 955 F.3d at 1093. As such, the EPA has a number of times in the past updated its MACT standards to reflect developments where the majority of sources were already outperforming the original MACT standards.[46] Indeed, this final rule is consistent with the EPA's authority pursuant to CAA section 112(d)(6) to take developments in practices, processes, and control technologies into account to determine if more stringent standards are achievable than those initially set by the EPA in establishing MACT floors, based on developments that occurred in the interim. *See LEAN* v. *EPA,* 955 F.3d 1088, 1097–98 (D.C. Cir. 2020). The technological standard approach of CAA section 112 is based on the premise that, to the extent there are controls available to reduce HAP emissions, and those controls are of reasonable cost, sources should be required to use them.

The fleet has been able to ''over comply'' with the existing fPM standard due to the very high PM control effectiveness of well-performing ESPs and FFs, often exceeding 99.9 percent. But the performance of a minority of units lags well behind the vast majority of the fleet. As indicated by the two highest fPM rates,[47] EGUs without the most effective PM controls have not been able to demonstrate fPM rates comparable to the rest of the fleet. Specifically, the Colstrip facility, a 1,500 MW subbituminous-fired power plant located in Colstrip, Montana, operates the only two coal-fired EGUs in the country without the most modern PM controls (*i.e.,* ESP or FF). Instead, this facility utilizes venturi wet scrubbers as its primary PM control technology and has struggled to meet the original 0.030 lb/MMBtu fPM limit, even while employing emissions averaging across the operating EGUs at the facility. Colstrip is also the only facility where the EPA estimates the current controls would be unable to meet a lower fPM limit. Specifically, the 2018 second quarter compliance stack tests showed average fPM emission rates above the 0.030 lb/MMBtu fPM limit, in violation of its Air Permit. Talen Energy, one of the owners of the facility, agreed to pay $450,000 to settle these air quality violations.[48] As a result, the plant was offline for approximately 2.5 months while the plant's operator worked to correct the problem. Comments from Colstrip's majority owners discuss the efforts this facility has undergone to improve their wet PM scrubbers, which they state remove 99.7 percent of the fly ash particulate but agree with the EPA that additional controls would be needed to meet a 0.010 lb/MMBtu limit. However, as stated in *NorthWestern Energy's Annual PCCAM Filing and Application of Tariff Changes*,[49] ''Colstrip has a history of operating very close to the upper end limit: for 43 percent of the 651 days of compliance preceding the forced outage its [Weighted Average Emission Rate or] WAER was within 0.03 lb/dekatherm[50] of the limit [. . . to comply with the Air Permit and MATS, Colstrip's WAER must be equal to or less than 0.03 lb/dekatherm].''

The Northern Cheyenne Reservation is 20 miles from the Colstrip facility and the Tribe exercised its authority in 1977 to require additional air pollution controls on the new Colstrip units (Colstrip 3 and 4, the same EGUs still operating today), recognizing the area as a Class I airshed under the CAA. According to comments submitted by the Northern Cheyenne Tribe, their tribal members—both those living on the Reservation and those living in the nearby community of Colstrip—have been disproportionally impacted by exposure to HAP emissions from the Colstrip facility.[51]

The EPA believes a fPM emission limit of 0.010 lb/MMBtu appropriately takes into consideration the costs of controls. The EPA evaluated the costs to improve current PM control systems and the cost to install better performing PM controls (*i.e.,* a new FF) to achieve a more stringent emission limit. Costs of PM upgrades are much lower than the EPA estimated in 2012, and the Agency revised its costs assumptions as described in the 2024 Technical Memo, available in the docket. Table 4 of this document summarizes the updated cost effectiveness of the three fPM emission limits considered in the 2023 Proposal for the existing coal-fired fleet. For the purpose of estimating cost effectiveness, the analysis presented in this table, described in detail in the 2023 and 2024 Technical Memos, is based on the observed emission rates of all existing coal-fired EGUs except for those that have announced plans to retire by the end of 2028. The analysis presented in table 4 estimated the costs associated for each unit to upgrade their existing PM controls to meet a lower fPM standard. In the cases where existing PM controls would not achieve the necessary reductions, unit-specific FF install costs were estimated. Unlike the cost and benefit projections presented in the RIA, the estimates in this table do not account for any future changes in the composition of the operational coal-fired EGU fleet that are likely to occur by 2028 as a result of other factors affecting the power sector, such as the IRA, future regulatory actions, or changes in economic conditions. For example, of the more than 14 GW of coal-fired capacity that the EPA estimates would require control improvements to achieve the final fPM rate, less than 12 GW is projected to be

---

exposure to cause adverse acute (or short-term) noncancer health effects.

[46] See, *e.g., National Emission Standards for Hazardous Air Pollutants: Site Remediation Residual Risk and Technology Review,* 85 FR 41680, 41698 (July 10, 2020) (proposed 84 FR 46138, 46161; September 3, 2019)) (requiring compliance with more stringent equipment leak definitions under a technology review, which were widely adopted by industry); *National Emissions Standards for Mineral Wool Production and Fiberglass Manufacturing,* 80 FR 45280, 45307 (July 29, 2015) (adopting more stringent limits for glass-melting furnaces under a technology review where the EPA found that ''all glass-melting furnaces were achieving emission reductions that were well below the existing MACT standards regardless of the control technology in use''); *National Emissions Standards for Hazardous Air Pollutants From Secondary Lead Smelting,* 77 FR 556, 564 (January 5, 2012) (adopting more stringent stack lead emission limit under a technology review ''based on emissions data collected from industry, which indicated that well-performing baghouses currently used by much of the industry are capable of achieving outlet lead concentrations significantly lower than the [current] limit.'').

[47] See figure 4 of the 2024 Technical Memo.

[48] See Document CLT–1T Testimony, CLT–11, and CL–12 in Docket 190882 at *https://www.utc.wa.gov/documents-and-proceedings/dockets.*

[49] See NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes, Docket No. 2019.09.058, Final Order 7708f paragraph 21 (November 18, 2020) (noting that ''Colstrip has a history of operating very close to the upper end limit''), available at *https://reddi.mt.gov/prweb.*

[50] For reference, a dekatherm is equivalent to one million Btus (MMBtu).

[51] See Document ID No. EPA–HQ–OAR–2018–5984 at *https://www.regulations.gov.*

operational in 2028 (see section 3 of the RIA for this final rule).

BILLING CODE 6560–50–P

Table 4. Summary of the Updated Cost Effectiveness Analysis for Three Potential fPM Limits[1]

	Potential fPM emission limit (lb/MMBtu)		
	0.015	0.010	0.006
Affected Units (Capacity, GW)	11 (4.7)	33 (14.1)	94 (41.3)
Annual Cost ($M, 2019 dollars)	38.8	87.2	398.8
fPM Reductions (tpy)	1,258	2,526	5,849
Total Non-Hg HAP Metals Reductions (tpy)	3.0	8.3	22.7
Total Non-Hg HAP Metals Cost Effectiveness ($k/ton)	13,050	10,500	17,500
Total Non-Hg HAP Metals Cost Effectiveness ($/lb)	6,500	5,280	8,790

[1] This analysis used reported fPM compliance data for 296 coal-fired EGUs to develop unit-specific average and lowest achieved fPM rate values to determine if the unit, with existing PM controls, could achieve a lower fPM limit. Using the compliance data, the EPA evaluated costs to upgrade existing PM controls, or if necessary, install new controls in order to meet a lower fPM limit.

BILLING CODE 6560–50–C

The EPA has updated its costs analyses for this final rule based on comments received and additional data review, which is described in more detail in the 2024 Technical Memo available in the docket. In response to commenters stating that the use of the lowest quarter's 99th percentile, or the lowest achievable fPM rate, is not indicative of overall EGU operation and emission performance, the EPA added a review of average fPM rates. In these updated analyses, both the lowest quarter's 99th percentile and the average fPM rate must be below the potential fPM limit for the EPA to assume no additional upgrades are needed to meet a revised limit. If an EGU has previously demonstrated an ability to meet a potential lower fPM limit, but the average fPM rate is greater than the potential limit, the analysis for the final rule has been updated to assume increased bag replacement frequency (for units with FFs) or operation and maintenance costing $100,000/year (2022$). This additional cost represents increased vigilance in maintaining ESP performance and includes technician labor to monitor performance of the ESP and to periodically make typical repairs (*e.g.,* replacement of failed insulators, damaged electrodes or other internals that may fail, repairing leaks in the ESP casing, ductwork, or expansion joints, and periodic testing of ESP flow balance and any needed adjustments).

Additionally, the Agency received comments that the PM upgrade costs estimated at proposal were too high on a dollar per ton basis and these costs have been updated and are provided in the 2024 Technical Memo. Specifically, commenters demonstrated that the observed percent reductions in fPM attributable to ESP upgrades were significantly greater than the percent reductions that the EPA had assumed for the proposed rule. Additionally, commenters demonstrated that ESP performance guarantees for coal-fired utility boilers were much lower than the EPA was aware of at proposal. These updates, as well as improving our methodology which increases the number of EGUs estimated to need PM upgrades, slightly lower the dollar per ton estimates from what was presented in the 2023 Proposal.

The EPA considers costs in various ways, depending on the rule and affected sector. For example, the EPA has considered, in previous CAA section 112 rulemakings, cost effectiveness, the total capital costs of proposed measures, annual costs, and costs compared to total revenues (*e.g.,* cost to revenue ratios).[52] As much of the

---

[52] See, *e.g., National Emission Standards for Hazardous Air Pollutants: Mercury Cell Chlor-Alkali Plants Residual Risk and Technology Review,* 87 FR 27002, 27008 (May 6, 2022) (considered annual costs and average capital costs per facility in technology review and beyond-the-floor analysis); *National Emission Standards for Hazardous Air Pollutants: Primary Copper Smelting Residual Risk and Technology Review and Primary Copper Smelting Area Source Technology Review,*

fleet is already reporting fPM emission rates below 0.010 lb/MMBtu, both the total costs and non-Hg HAP metal reductions of the revised limit are modest in context of total PM upgrade control costs and emissions of the coal fleet. The cost-effectiveness estimate for EGUs reporting average fPM rates above the final fPM emission limit of 0.010 lb/MMBtu is $10,500,000/ton of non-Hg HAP metals, slightly lower than the range presented in the 2023 Proposal.

Further, the EPA finds that costs for facilities to meet the revised fPM emission limit represent a small fraction of typical capital and total expenditures for the power sector. In the 2022 Proposal (reaffirming the appropriate and necessary finding), the EPA evaluated the compliance costs that were projected in the 2012 MATS Final Rule relative to the typical annual revenues, capital expenditures, and total (capital and production) expenditures.[53] 87 FR 7648–7659 (February 9, 2022); 80 FR 37381 (June 30, 2015). Using electricity sales data from the U.S. Energy Information Administration (EIA), the EPA updated the analysis presented in the 2022 Proposal. We find revenues from retail electricity sales increased from $333.5 billion in 2000 to a peak of $429.6 billion in 2008 (an increase of about 29 percent during this period) and slowly declined since to a post-2011 low of $388.6 billion in 2020 (a decrease of about 10 percent from its peak during this period) in 2019 dollars.[54] Revenues increased in 2022 to nearly the same amount as the 2008 peak ($427.8 billion). The annual control cost estimate for the final fPM standard based on the cost-effectiveness analysis in table 4 (see section 1c of the 2024 Technical Memo) of this document is a very small share of total power sector sales (about 0.03 percent of the lowest year over the 2000 to 2019 period). Making similar comparisons of the estimated capital and total compliance costs to historical trends in sector-level capital and production costs, respectively, would yield similarly small estimates. Therefore, as in previous CAA section 112 rulemakings, the EPA considered costs in many ways, including cost effectiveness, the total capital costs of proposed measures, annual costs, and costs compared to total revenues to determine the appropriateness of the revised fPM standard under the CAA section 112(d)(6) technology review, and determined the costs are reasonable.

In this final rule, the EPA finds that costs of the final fPM standard are reasonable, and that the revised fPM standard appropriately balances the EPA's obligation under CAA section 112 to achieve the maximum degree of emission reductions considering statutory factors, including costs. Further, the EPA finds that its consideration of costs is consistent with D.C. Circuit precedent, which has found that CAA section 112(d)(2) expressly authorizes cost consideration in other aspects of the standard-setting process, such as CAA section 112(d)(6), *see Association of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667, 673–74 (D.C. Cir. 2013), and that CAA section 112 does not mandate a specific method of cost analysis in an analogous situation when considering the beyond-the-floor review. *See NACWA* v. *EPA,* 734 F.3d 1115, 1157 (D.C. Cir. 2013) (finding the statute did not ''mandate a specific method of cost analysis''); *see also NRDC* v. *EPA,* 749 F.3d 1055, 1060–61 (D.C. Cir. 2014).

As discussed in section IV.C.1. in response to comments regarding the relatively higher dollar per ton cost effectiveness of the final fPM standard, the EPA finds that in the context of this industry and this rulemaking, the updated standards are an appropriate exercise of the EPA's standard setting authority pursuant to the CAA section 112(d)(6) technology review. As commenters rightly note, the EPA routinely considers the cost effectiveness of potential standards where it can consider costs under CAA section 112, *e.g.,* in conducting beyond-the-floor analyses and technology reviews, to determine the achievability of a potential control option. And the D.C. Circuit recognized that the EPA's interpretation of costs as ''allowing consideration of cost effectiveness was reasonable.'' *NRDC* v. *EPA,* 749 F.3d 1055, 1060–61 (D.C. Cir. 2014) (discussing the EPA's consideration of cost effectiveness pursuant to a CAA section 112(d)(2) beyond-the-floor analysis). However, cost effectiveness is not the sole factor that the EPA considers when determining the achievability of a potential standard in conducting a technology review, nor is cost effectiveness the only value that the EPA considers with respect to costs.[55] Some commenters pointed to other rulemakings (which are discussed in section IV.C.1. above) where the EPA determined not to pursue potential control options with relatively higher cost-effectiveness estimates as compared to prior CAA section 112 rulemakings. However, there were other factors that the EPA considered, in addition to cost effectiveness, that counseled against pursuing such updates. In this rulemaking, the EPA finds that several factors discussed throughout this record make promulgation of the new fPM standard appropriate under CAA section 112(d)(6). First, a wide majority of units have invested in the most-effective PM controls and are already demonstrating compliance with the new fPM standard and at lower costs than assumed during promulgation of the original MATS fPM emission limit. Of the 33 EGUs that the EPA estimated would require control improvements to meet a 0.010 lb/MMBtu fPM standard, only two are not using the most effective PM control technologies available. The EPA assumed that these two units would need to install FFs to achieve the 0.010 lb/MMBtu emission standard, and the cost of those FF retrofits accounts for 42 percent of the total annualized costs presented in table 4. Further, 11 EGUs that the EPA assumed would require different levels of ESP upgrades to meet the 0.010 lb/MMBtu emission standard (all of which have announced retirement dates between 2031 and 2042 resulting in shorter assumed amortization periods) account for about 57 percent of the total annualized costs. The remaining 1 percent of the total annualized costs are associated with 10 EGUs with existing FFs that the EPA

---

87 FR 1616, 1635 (proposed January 11, 2022) (considered total annual costs and capital costs, annual costs, and costs compared to total revenues in proposed beyond-the-floor analysis); *Phosphoric Acid Manufacturing and Phosphate Fertilizer Production RTR and Standards of Performance for Phosphate Processing,* 80 FR 50386, 50398 (August 19, 2015) (considered total annual costs and capital costs compliance costs and annualized costs for technology review and beyond the floor analysis); *National Emissions Standards for Hazardous Air Pollutants: Ferroalloys Production,* 80 FR 37366, 37381 (June 30, 2015) (considered total annual costs and capital costs, annual costs, and costs compared to total revenues in technology review); *National Emission Standards for Hazardous Air Pollutants: Off-Site Waste and Recovery Operations,* 80 FR 14248, 14254 (March 18, 2015) (considered total annual costs and capital costs, and average annual costs and capital costs and annualized costs per facility in technology review); *National Emission Standards for Hazardous Air Pollutant Emissions: Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks; and Steel Pickling-HCl Process Facilities and Hydrochloric Acid Regeneration Plants,* 77 FR 58220, 58226 (September 19, 2012) (considered total annual costs and capital costs in technology review); *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews,* 77 FR 49490, 49523 (August 16, 2012) (considered total capital costs and annualized costs and capital costs in technology review). *C.f. NRDC* v. *EPA,* 749 F.3d 1055, 1060 (D.C. Cir. 2014).

[53] See Cost TSD for 2022 Proposal at Document ID No. EPA–HQ–OAR–2018–0794–4620 at *https://www.regulations.gov.*

[54] 2019 dollars were used for consistency with the 2023 Proposal.

[55] See note 50, above, for examples of other costs metrics the EPA has considered in prior CAA section 112 rulemakings.

assumes will require bag upgrades or increased bag changeouts and 10 EGUs that are assumed to need additional operation and maintenance of existing ESPs, which is further explained in the 2024 Technical Memo. Since only a small handful of units emit significantly more than peer facilities, the Agency finds these upgrades appropriate. Additionally, the size and unique nature of the coal-fired power sector, and the emission reductions that will be achieved by the new standard, in addition to the costs, make promulgation of the new standard appropriate under CAA section 112(d)(6).

The power sector also operates differently than other industries regulated under CAA section 112.[56] For example, the power sector is publicly regulated, with long-term decision-making and reliability considerations made available to the public; it is a data-rich sector, which generally allows the EPA access to better information to inform its regulation; and the sector is in the midst of an energy generation transition leading to plant retirements that are independent of EPA regulation. Because of the relative size of the power sector, while cost effectiveness of the final standard is relatively high as compared to prior CAA section 112 rulemakings involving other industries, costs represent a much smaller fraction of industry revenue. In the likely case that the power sector's transition to lower-emitting generation is accelerated by the IRA, for example, the total costs and emission reductions achieved by each final fPM standard in table 4 of this document would also be an overestimate.

As demonstrated in the proposal, the power sector, as a whole, is achieving fPM emission rates that are well below the 0.030 lb/MMBtu standard from the 2012 Final MATS Rule, with the exception of a few outlier facilities. The EPA estimates that only one facility (out of the 151 evaluated coal-fired facilities), which does not have the most modern PM pollution controls and has been unable to demonstrate an ability to meet a lower fPM limit, will be required to install the most-costly upgrade to meet the revised standards, which significantly drives up the cost of this final rule. However, the higher costs for one facility to install demonstrated improvements to its control technology should not prevent the EPA from establishing achievable standards for the sector under the EPA's CAA section 112(d)(6) authority. Instead, the EPA finds that it is consistent with its CAA section 112(d)(6) authority to consider the performance of the industry at large. The average fPM emissions of the industry demonstrate the technical feasibility of higher emitting facilities to meet the new standard and shows there are proven technologies that if installed at these units will allow them to significantly lower fPM and non-Hg HAP metals emissions.

In this rulemaking, the EPA also determined not to finalize a more stringent standard for fPM emissions, such as a limit of 0.006 lb/MMBtu or lower, which the EPA took comment on in the 2023 Proposal. The EPA declines to finalize an emission standard of 0.006 lb/MMBtu or lower primarily due to technical limitations in using PM CEMS for compliance demonstration purposes described in the next section. The EPA has determined that a fPM emission standard of 0.010 lb/MMBtu is the lowest that would also allow the use of PM CEMS for compliance demonstration. Additionally, the EPA also considered the overall higher costs associated with a more stringent standard as compared to the final standard, which the EPA considered under the technology review.

Additionally, compliance with a fPM emission limit of 0.006 lb/MMBtu could only be demonstrated using periodic stack testing that would require test run durations longer than 4 hours[57] and would not provide the source, the public, and regulatory authorities with continuous, transparent data for all periods of operation. Establishing a fPM limit of 0.006 lb/MMBtu while maintaining the current compliance demonstration flexibilities of quarterly ''snapshot'' stack testing would, theoretically, result in greater emission reductions; however, the measured emission rates are only representative of rates achieved at optimized conditions at full load. While coal-fired EGUs have historically provided baseload generation, they are being dispatched much more as load following generating sources due to the shift to more available and cheaper natural gas and renewable generation. As such, traditional generation assets—such as coal-fired EGUs—will likely continue to have more startup and shutdown periods, more periods of transient operation as load following units, and increased operation at minimum levels, all of which can produce higher PM emission rates. Maintaining the status quo with quarterly stack testing will likely mischaracterize emissions during these changing operating conditions. Thus, while a fPM emission limit of 0.006 lb/MMBtu paired with use of quarterly stack testing may appear to be more stringent than the 0.010 lb/MMBtu standard paired with use of PM CEMS that the EPA is finalizing in this rule, there is no way to confirm emission reductions during periods in between quarterly tests when emission rates may be higher. Therefore, the Agency is finalizing a fPM limit of 0.010 lb/MMBtu with the use of PM CEMS as the only means of compliance demonstration. The EPA has determined that this combination of fPM limit and compliance demonstration represents the most stringent available option taking into account the statutory considerations.

The EPA also determined not to finalize a fPM standard of 0.015 lb/MMBtu, which the EPA took comment on in the 2023 Proposal, because the EPA determined that a standard of 0.010 lb/MMBtu is appropriate for the reasons discussed above.

In this rule, the EPA is also reaching a different conclusion from the 2020 Technology Review with respect to the fPM emission standard and requirements to utilize PM CEMS. As discussed in section II.D. above, the 2020 Technology Review did not consider developments in the cost and effectiveness of proven technologies to control fPM as a surrogate for non-Hg HAP metals emissions, nor did the EPA evaluate the current performance of emission reduction control equipment and strategies at existing MATS-affected EGUs. In this rulemaking, in which the EPA reviewed the findings of the 2020 Technology Review, the Agency determined there are important developments regarding the emissions performance of the coal-fired EGU fleet, and the costs of achieving that performance that are appropriate for the EPA to consider under its CAA section 112(d)(6) authority, and which are the basis for the revised emissions standards the EPA is promulgating through this final rule.

The 2012 MATS Final Rule contains emission limits for both individual and total non-Hg HAP metals (*e.g.,* lead, arsenic, chromium, nickel, and cadmium), as well as emission limits for fPM. Those non-Hg HAP metals

---

[56] This is a fact which Congress recognized in requiring the EPA to first determine whether regulation of coal-fired EGUs was ''appropriate and necessary'' under CAA section 112(n)(1)(A) before proceeding to regulate such facilities under CAA section 112's regulatory scheme.

[57] Run durations greater than 4 hours would ensure adequate sample collection and lower random error contributions to measurement uncertainty for a limit of 0.006 lb/MMBtu. The EPA aims to keep run durations as short as possible, generally at least one but no more than 4 hours in length, in order to minimize impacts to the facility (*e.g.,* overall testing campaign testing costs, employee focused attention and safety).

emission limits serve as alternative emission limits because fPM was found to be a surrogate for either individual or total non-Hg HAP metals emissions. While EGU owners or operators may choose to demonstrate compliance with either the individual or total non-Hg HAP metals emission limits, the EPA is aware of just one owner or operator who has provided non-Hg HAP metals data—both individual and total—along with fPM data, for compliance demonstration purposes. This is for a coal refuse-fired EGU with a generating capacity of 46.1 MW. Given that owners or operators of all the other EGUs that are subject to the requirements in MATS have chosen to demonstrate compliance with only the fPM emission limit, the EPA proposed to remove the total and individual non-Hg HAP metals emission limits from all existing MATS-affected EGUs and solicited comment on our proposal. In the alternative, the EPA took comment on whether to retain total and/or individual non-Hg HAP metals emission limits that have been lowered proportionally to the revised fPM limit (*i.e.,* revised lower by two-thirds to be consistent with the revision of the fPM standard from 0.030 lb/MMBtu to 0.010 lb/MMBtu).

Commenters urged the EPA to retain the non-Hg HAP metals limits, arguing it is incongruous for the EPA to eliminate the measure for the pollutants that are the subject of regulation under CAA section 112(d)(6), notwithstanding the fact that the fPM limit serves as a more easily measurable surrogate for these HAP metals. Additionally, some commenters stated that the inability to monitor HAP metals directly will significantly impair the EPA's ability to revise emission standards in the future.

After considering comments, the EPA determined to promulgate revised total and individual non-Hg HAP metals emission limits for coal-fired EGUs that are lowered proportionally to the revised fPM standard. Just as this rule requires owners or operators to demonstrate continuous compliance with fPM limits, owners or operators who choose to demonstrate compliance with these alternative limits will need to utilize approaches that can measure non-Hg HAP metals on a continuous basis—meaning that intermittent emissions testing using Reference Method 29 will not be a suitable approach. Owners or operators may petition the Administrator to utilize an alternative test method that relies on continuous monitoring (*e.g.,* multi-metal CMS) under the provisions of 40 CFR 63.7(f). The EPA disagrees with the suggestion that failure to monitor HAP metals directly could impair the ability to revise those standards in the future.

2. Rationale for the Final Compliance Demonstration Options

In the 2023 Proposal, the EPA proposed to require that coal- and oil-fired EGUs utilize PM CEMS to demonstrate compliance with the fPM standard used as a surrogate for non-Hg HAP metals. The EPA proposed the requirement for PM CEMS based on its assessment of costs of PM CEMS versus stack testing, and the many other benefits of using PM CEMS including increased transparency and accelerated identification of anomalous emissions. In particular, the EPA noted the ability for PM CEMS to provide continuous feedback on control device and plant operations and to provide EGU owners and operators, regulatory authorities, and members of nearby communities with continuous assurance of compliance with emissions limits as an important benefit. Further, the EPA explained in the 2023 Proposal that PM CEMS are currently in use by approximately one-third of the coal-fired fleet, and that PM CEMS can provide low-level measurements of fPM from existing EGUs.

After considering comments and conducting further analysis,[58] the EPA is finalizing the use of PM CEMS for compliance demonstration purposes for coal- and oil-fired EGUs pursuant to its CAA section 112(d)(6) authority. As discussed in section IV.D.1. above, Congress intended for CAA section 112 to achieve significant reductions in HAP, which it recognized as particularly harmful pollutants. The EPA finds that the benefits of PM CEMS to provide real-time information to owners and operators (who can promptly address any problems with emissions control equipment), to regulators, to adjacent communities, and to the general public, further Congress's goal to ensure that emission reductions are consistently maintained. The EPA determined not to require PM CEMS for existing IGCC EGUs, described in section VI.D., due to technical issues calibrating CEMS on these types of EGUs due to the difficulty in preparing a correlation range because these EGUs are unable to de-tune their fPM controls and their existing emissions are less than one-tenth of the final emission limit. Further, the EPA finds additional authority to require the use of PM CEMS under CAA section 114(a)(1)(C), which allows that the EPA may require a facility that ''may have information necessary for the purposes set forth in this subsection, or who is subject to any requirement of this chapter'' to ''install, use, and maintain such monitoring equipment'' on a ''on a one-time, periodic or continuous basis.'' 114(a)(1)(C).

From the EPA's review of PM CEMS, the Agency determined that a fPM standard of 0.010 lb/MMBtu with adjusted QA criteria—used to verify consistent correlation of CEMS data initially and over time—is the lowest fPM emission limit possible at this time with use of PM CEMS.[59] PM CEMS correlated using these values will ensure accurate measurements—either above, at, or below this emission limit. As discussed in section IV.D.1. above, one of the reasons the EPA determined not to finalize a more stringent standard for fPM is because it would prove challenging to verify accurate measurement of fPM using PM CEMS. Specifically, as mentioned in the *Suitability of PM CEMS Use for Compliance Determination for Various Emission Levels,* memorandum, available in the docket, no fPM standard more stringent than 0.010 lb/MMBtu with adjusted QA criteria is expected to have acceptable passing rates for the QA checks or acceptable random error for reference method testing.

At proposal, the EPA estimated that the EUAC of PM CEMS was $60,100 (88 FR 24873). Based on comments the EPA received on the costs and capabilities of PM CEMS and additional analysis the EPA conducted, the EPA determined that the revised EUAC of PM CEMS is higher than estimated at proposal. The EPA now estimates that the EUAC of non-beta gauge PM CEMS is $72,325, which is 17 percent less than what was estimated for the 2012 MATS Final Rule. That amount is somewhat greater than the revised estimated costs of infrequent emission testing (generally quarterly)—the revised average estimated costs of such infrequent emissions testing using EPA Method 5I[60] is $60,270.[61]

In choosing a compliance demonstration requirement, the EPA considers multiple factors, including

---

[58] The EPA explains additional analyses of PM CEMS in the memos titled *Suitability of PM CEMS Use for Compliance Determination for Various Emissions Levels* and *Summary of Review of 36 PM CEMS Performance Test Reports versus PS11 and Procedure 2 of 40 CFR part 60, appendices B and F, respectively,* which are available in the docket.

[59] The EPA notes that the fPM standard [0.010 lb/MMBtu] is based on hourly averages obtained from PM CEMS over 30 boiler operating days [see 40 CFR 63.10021(b)].

[60] Method 5I is one of the EPA's reference test methods for PM. See 40 CFR part 60, appendix A.

[61] See *Revised Estimated Non-Beta Gauge PM CEMS and Filterable PM Testing Costs* memorandum, available in the docket.

costs, benefits of the compliance technique, technical feasibility and commercial availability of the compliance method, ability of personnel to conduct the compliance method, and continuity of data used to assure compliance. PM CEMS are readily available and in widespread use by the electric utility industry, as evidenced by the fact that over 100 EGUs already utilize PM CEMS for compliance demonstration purposes. Moreover, the electric utility industry and its personnel have demonstrated the ability to install, operate, and maintain numerous types of CEMS—including PM CEMS. As mentioned earlier, EGU owners and/or operators who chose PM CEMS for compliance demonstration have attested in their submitted reports to the suitability of their PM CEMS to measure at low emission levels, certifying fPM emissions lower than 0.010 lb/MMBtu with their existing correlations developed using emission levels at 0.030 lb/MMBtu. The EPA conducted a review of eight EGUs with varying fPM control devices that rely on PM CEMS that showed certified emissions ranging from approximately 0.002 lb/MMBtu to approximately 0.007 lb/MMBtu. The EPA's review analyzed 30 boiler operating day rolling averages obtained from reports posted to WebFIRE for the third quarter of 2023 from these eight EGUs.[62]

As described in the *Summary of Review of 36 PM CEMS Performance Test Reports versus PS11 and Procedure 2 of 40 CFR part 60, Appendices B and F* memorandum, available in the docket, the EPA investigated how well a sample of EGUs using PM CEMS for compliance purposes would meet initial and ongoing QA requirements at various emission limit levels, even though no change in actual EGU operation occurred. As described in the aforementioned *Suitability of PM CEMS Use for Compliance Determination for Various Emission Levels* memorandum, as the emission limit is lowered, the ability to meet both components necessary to correlate PM CEMS—acceptable random error and QA passing rate percentages—becomes more difficult. Based on this additional analysis and review, the EPA determined to finalize requirements to use PM CEMS with adjusted QA criteria and a 0.010 lb/MMBtu fPM emission limit as the most stringent limit possible with PM CEMS.

Use of PM CEMS can provide EGU owners or operators with an increased ability to detect and correct potential problems before degradation of emission control equipment, reduction or cessation of electricity production, or exceedances of regulatory emission standards. As mentioned in the *Ratio of Revised Estimated Non-Beta Gauge PM CEMS EUAC to 2022 Average Coal-Fired EGU Gross Profit* memorandum, using PM CEMS can be advantageous, particularly since their EUAC is offset if their use allows owners or operators to avoid 3 or more hours of generating downtime per year.

In deciding whether to finalize the proposal to use PM CEMS as the only compliance demonstration method for non-IGCC coal- and oil-fired EGUs, the Agency assessed the costs and benefits afforded by requiring use of only PM CEMS as compared to continuing the current compliance demonstration flexibilities (*i.e.,* allowing use of either PM CEMS or infrequent PM emissions stack testing). As mentioned above, the average annual cost for quarterly stack testing provided by commenters is about $12,000 less than the EUAC for PM CEMS. While no estimate of quantified benefits was provided by commenters, the EPA recognizes that the 35,040 15-minute values provided by a PM CEMS used at an EGU operating during a 1-year period is over 243 times as much information as is provided by quarterly testing with three 3-hour run durations. This additional, timely information provided by PM CEMS affords the adjacent communities, the general public, and regulatory authorities with assurances that emission limits and operational processes remain in compliance with the rule requirements. It also provides EGU owners or operators with the ability to quickly detect, identify, and correct potential control device or operational problems before those problems become compliance issues. When establishing emission standards under CAA section 112, the EPA must select an approach to compliance demonstration that best assures compliance is being achieved.

The continuous monitoring of fPM required in this rule provides several benefits which are not quantified in this rule, including greater certainty, accuracy, transparency, and granularity in fPM emissions information than exists today. Continuous measurement of emissions accounts for changes to processes and fuels, fluctuations in load, operations of pollution controls, and equipment malfunctions. By measuring emissions across all operations, power plant operators and regulators can use the data to ensure controls are operating properly and to assess compliance with relevant standards. Because CEMS enable power plant operators to quickly identify and correct problems with pollution control devices, it is possible that continuous monitoring could lead to lower fPM emissions for periods of time between otherwise required intermittent testing, currently up to 3 years for some units.

To illustrate the potentially substantial differences in fPM emissions between intermittent and continuous monitoring, the EPA analyzed emissions at several EGUs for which both intermittent and continuous monitoring data are available. This analysis is provided in the 2024 Technical Memo, available in the rulemaking docket. For example, one 585-MW bituminous-fired EGU, with a cold-side ESP for PM control, has achieved LEE status for fPM and is currently required to demonstrate compliance with an emission standard of 0.015 lb/MMBtu using intermittent stack testing every 3 years. In the most recent LEE compliance report, submitted on February 25, 2021, the unit submitted the result of an intermittent stack test with an emission rate of 0.0017 lb/MMBtu. In the subsequent 36 months over which this unit is currently not subject to any further compliance testing, continuous monitoring demonstrates that the fPM emission rate increased substantially. At one point, the continuously monitored 30-day rolling average emissions rate[63] was nine times higher than the intermittent stack test average, reaching the fPM LEE limit of 0.015 lb/MMBtu. In this example, the actual continuously monitored daily average emissions rate over the February 2021 to April 2023 period ranged from near-zero to 0.100 lb/MMBtu. Emissions using either the stack test average or hourly PM CEMS data were calculated for 2022 for this unit. Both approaches indicate fPM emissions well below the allowable levels for a fPM limit of 0.010 lb/MMBtu, while estimates using PM CEMS are about 2.5 times higher than the stack test estimate. Additional examples of differences between intermittent stack testing and continuous monitoring are provided in the 2024 Technical Memo, including for periods when PM CEMS data is lower

---

[62] See Third Quarter 2023 p.m. CEMS Thirty Boiler Operating Day Rolling Average Reports for Iatan Generating Station units 1 and 2, Missouri; Marshall Steam Station units 1 and 3, North Carolina; Kyger Creek Station unit 3, Ohio; Virginia City Hybrid Energy Center units 1 and 2, Virginia; and Ghent Generating Station unit 1, Kentucky. These reports are available electronically by searching in the WebFIRE Report Search and Retrieval portion of the Agency's WebFIRE internet website at *https://cfpub.epa.gov/webfire/reports/esearch.cfm.*

[63] The 30-day rolling average emission rate was calculated by taking daily fPM rate averages over a 30-day operating period while filtering out hourly fPM data during periods of startup and shutdown.

than the stack test averages,[64] which further illustrate real-life scenarios in which fPM emissions for compliance methods may be substantially different.

The potential reduction in fPM and non-Hg HAP metals emission resulting from the information provided by continuous monitoring coupled with corrective actions by plant operators could be sizeable over the total capacity that the EPA estimates would install PM CEMS under this rule (nearly 82 GW). Furthermore, the potential reduction in non-Hg HAP metal emissions would likely reduce exposures to people living in proximity to the coal-fired EGUs potentially impacted by the amended fPM standards. The EPA has found that populations living near coal-fired EGUs have a higher percentage of people living below two times the poverty level than the national average.

In addition to significant value of further pollution abatement, the CEMS data are transparent and accessible to regulators, stakeholders, and the public, fostering greater accountability. Transparency of EGU emissions as provided by PM CEMS, along with real-time assurance of compliance, has intrinsic value to the public and communities as well as instrumental value in holding sources accountable. This transparency is facilitated by a requirement for electronic reporting of fPM emissions data by the source to the EPA. This emissions data, once submitted, becomes accessible and downloadable—along with other operational and emissions data (*e.g.,* for SO_2, CO_2, NO_X, Hg, *etc.*) for each covered source.

On balance, the Agency finds that the benefits of emissions transparency and the continuous information stream provided by PM CEMS coupled with the ability to quickly detect and correct problems outweigh the minor annual cost differential from quarterly stack testing. The EPA is finalizing, as proposed, the use of PM CEMS to demonstrate compliance with the fPM emission standards for coal- and oil-fired EGUs (excluding IGCC units and limited-use liquid-oil-fired EGUs).

More information on the proposed technology review can be found in the 2023 Technical Memo (Document ID No. EPA–HQ–OAR–2018–0794–5789), in the preamble for the 2023 Proposal (88 FR 24854), and the 2024 Technical Memo, available in the docket. For the reasons discussed above, pursuant to CAA section 112(d)(6), the EPA is finalizing, as proposed, the use of PM CEMS (with adjusted QA criteria as a result of review of comments) for the compliance demonstration of the fPM emission standard (as a surrogate for non-Hg HAP metal) for coal- and oil-fired EGUs, and the removal of the fPM and non-Hg HAP metals LEE provisions.

V. What is the rationale for our final decisions and amendments to the Hg emission standard for lignite-fired EGUs from review of the 2020 Technology Review?

A. What did we propose pursuant to CAA section 112(d)(6) for the lignite-fired EGU subcategory?

In the 2012 MATS Final Rule, the EPA finalized a Hg emission standard of 4.0E-06 lb/MMBtu (4.0 lb/TBtu) for a subcategory of existing lignite-fired EGUs.[65] The EPA also finalized a Hg emission standard of 1.2E-06 lb/MMBtu (1.2 lb/TBtu) for coal-fired EGUs not firing lignite (*i.e.,* for EGUs firing anthracite, bituminous coal, subbituminous coal, or coal refuse); and the EPA finalized a Hg emission output-based standard for new lignite-fired EGUs of 0.040 lb/GWh and a Hg emission output-based standard for new non-lignite-fired EGUs of 2.0E-04 lb/GWh. In 2013, the EPA reconsidered the Hg emission standard for new non-lignite-fired EGUs and revised the output-based standard to 0.003 lb/GWh (see 78 FR 24075).

As explained in the 2023 Proposal, Hg emissions from the power sector have declined since promulgation of the 2012 MATS Final Rule with the installation of Hg-specific and other control technologies and as more coal-fired EGUs have retired or reduced utilization. The EPA estimated that 2021 Hg emissions from coal-fired EGUs were 3 tons (a 90 percent decrease compared to pre-MATS levels). However, units burning lignite (or permitted to burn lignite) accounted for a disproportionate amount of the total Hg emissions in 2021. As shown in table 5 in the 2023 Proposal (88 FR 24876), 16 of the top 20 Hg-emitting EGUs in 2021 were lignite-fired EGUs. Overall, lignite-fired EGUs were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs in 2021, while generating about 7 percent of total 2021 megawatt-hours. Lignite accounted for 8 percent of total U.S. coal production in 2021.

Prior to the 2023 Proposal, the EPA assembled information on developments in Hg emission rates and installed controls at lignite-fired EGUs from operational and emissions information that is provided routinely to the EPA for demonstration of compliance with MATS and from information provided to the EIA. In addition, the EPA's final decisions were informed by information that was submitted as part of a CAA section 114 information survey (2022 ICR). The EPA also revisited information that was used in establishing the emission standards in the 2012 Final MATS Rule and considered information that was submitted during the public comment period for the 2023 Proposal. From that information, the EPA determined, as explained in the 2023 Proposal, that there are available cost-effective control technologies and improved methods of operation that would allow existing lignite-fired EGUs to achieve a more stringent Hg emission standard. As such, the EPA proposed a revised Hg emission standard for existing EGUs firing lignite (*i.e.,* for those in the ''units designed for low rank virgin coal'' subcategory). Specifically, the EPA proposed that such lignite-fired units must meet the same emission standard as existing EGUs firing other types of coal (*e.g.,* anthracite, bituminous coal, subbituminous coal, and coal refuse), which is 1.2 lb/TBtu (or an alternative output-based standard of 0.013 lb/GWh). The EPA did not propose to revise the Hg emission standards either for existing EGUs firing non-lignite coal or for new non-lignite coal-fired EGUs.[66]

B. How did the technology review change for the lignite-fired EGU subcategory?

The outcome of the technology review for the Hg standard for existing lignite-fired EGUs has not changed since the 2023 Proposal. However, in response to comments, the EPA expanded its review to consider additional coal compositional data and the impact of sulfur trioxide (SO_3) in the flue gas.

---

[64] See Case Study 2 in the 2024 Technical Memo, which shows long time periods of PM CEMS data below the most recent RRA. Note this unit uses PM CEMS for compliance with the fPM standard, so the RRA is used as an indicator of stack test results.

[65] The EPA referred to this subcategory in the final rule as ''units designed for low rank virgin coal.'' The EPA went on to specify that such a unit is designed to burn and is burning non-agglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) and that is constructed and operates at or near the mine that produces such coal. The EPA also finalized an alternative output-based emission standard of 0.040 lb/GWh. Currently, the approximately 22 units that are permitted as lignite-fired EGUs are located exclusively in North Dakota, Texas, and Mississippi.

[66] As stated in the 2023 Proposal, when proposed revisions to existing source emission standards are more stringent than the corresponding new source emission standard, the EPA proposes to revise the corresponding new source standard to be at least as stringent as the proposed revision to the existing source standard. This is the case with the Hg emission standard for new lignite-fired sources, which will be adjusted to be as stringent as the existing source standard.

C. What key comments did we receive on the Hg emission standard for lignite-fired EGUs, and what are our responses?

The Agency received both supportive and critical comments on the proposed revision to the Hg emission standard for existing lignite-fired EGUs. Some commenters agreed with the EPA's decision to not propose revisions to the Hg emission standards for non-lignite-fired EGUs, while others disagreed. Significant comments are summarized below, and the Agency's responses are provided.

Comment: Several commenters stated that industry experience confirms that stringent limits on power plant Hg emissions can be readily achieved at lower-than-predicted costs and thus should be adopted nationally through CAA section 112(d)(6). They said that at least 14 states have, for years, enforced state-based limits on power plant Hg emissions, and nearly every one of those states has imposed more stringent emission limits than those proposed in this rulemaking or in the final 2012 MATS Final Rule. The commenters said that these lower emissions limits have resulted in significant and meaningful Hg emission reductions, which have proven to be both achievable and cost-effective.

Some commenters recommended that the EPA revise the Hg limits to levels that are much more stringent than existing or proposed standards for both EGUs firing non-lignite coals and those firing lignite. They claimed that more stringent Hg emission standards are supported by developments in practices, processes, and control technologies. They pointed to a 2021 report by Andover Technology Partners, which details advances in control technologies that support more stringent Hg standards for all coal-fired EGUs.[67] These advances include advanced activated carbon sorbents with higher capture capacity at lower injection rates and carbon sorbents that are tolerant of flue gas species.

Response: The EPA has taken these comments and the referenced information into consideration when establishing the final emission standards. The EPA disagrees that the Agency should, in this final rule, revise the Hg limits for all coal-fired EGUs to levels more stringent than the current or proposed standards. The Agency did not propose in the 2023 Proposal to revise the Hg emission standard for ''not-low-rank coal units'' (*i.e.,* those EGUs that are firing on coals other than lignite) and did not suggest an emission standard for lignite-fired EGUs more stringent than the 1.2 lb/TBtu emission standard that was proposed. However, the EPA will continue to review emission standards and other rule requirements as part of routine CAA section 112(d)(6) technology reviews, which are required by statute to be conducted at least every 8 years. If we determine in subsequent CAA section 112(d)(6) technology reviews that further revisions to Hg emission standards (or to standards for other HAP or surrogate pollutants) are warranted, then we will propose revisions at that time. We discuss the rationale for the final emission standards in section V.D. of this preamble and in more detail in the 2024 Technical Memo.

Comment: Several commenters challenged the data that the EPA used in the CAA 112(d)(6) technology review. Commenters stated that the information collected by the EPA via the CAA section 114 request consisted of 17 units each submitting two 1-week periods of data and associated operational data preselected by the EPA, and that only a limited number of the EGUs reported burning only lignite. Other EGUs reported burning primarily refined coal, co-firing with natural gas, and firing or co-firing with large amounts of subbituminous coal (referencing table 7 in the 2023 Proposal). Commenters stated that if the EPA's intent was to assess the Hg control performance of lignite-fired EGUs, then the EGUs evaluated should have burned only lignite, not refined coal, subbituminous coal, or natural gas.

Response: The EPA disagrees with the commenters' argument that the Agency should have only considered emissions and operational data from EGUs that were firing only lignite. The EPA's intent was to evaluate the Hg emission control performance of units that are permitted to burn lignite and are thus subject to a Hg emission standard of 4.0 lb/TBtu. According to fuel use information supplied to EIA on form 923,[68] 13 of 22 EGUs that were designed to burn lignite utilized ''refined coal'' to some extent in 2021, as summarized in table 7 in the 2023 Proposal preamble (88 FR 24878). EIA form 923 does not specify the type of coal that is ''refined'' when reporting boiler or generator fuel use. For the technology review, the EPA assumed that the facilities utilized ''refined lignite,'' as reported in fuel receipts on EIA form 923. In any case, firing of refined lignite or subbituminous coal or co-firing with natural gas or fuel oil are considered to be Hg emission reduction strategies for a unit that is subject to an emission standard of 4.0 lb/TBtu, which was based on the use of lignite as its fuel.

In a related context, in *U.S. Sugar Corp.* v. *EPA,* the D.C. Circuit held that the EPA could not exclude unusually high performing units within a subcategory from the Agency's determination of MACT floor standards for a subcategory pursuant to CAA section 112(d)(3). 830 F.3d 579, 631–32 (D.C. Cir. 2016) (finding ''an unusually high-performing source should be considered[,]'' in determining MACT floors for a subcategory, and that ''its performance suggests that a more stringent MACT standard is appropriate.''). While the technology review at issue here is a separate and distinct analysis from the MACT floor setting requirements at issue in *U.S. Sugar* v. *EPA,* similarly here the EPA finds it is appropriate to consider emissions from all units that are permitted to burn lignite and are therefore subject to the prior Hg emission standard of 4.0 lb/TBtu and are part of the lignite-fired EGU subcategory, for the purposes of determining whether more stringent standards are appropriate under a technology review. However, while the EPA has considered the emissions performance of all units within the lignite-fired EGU subcategory, it is not the performance of units that are firing or co-firing with other non-lignite fuels that provide the strongest basis for the more stringent standard. Rather, the most convincing evidence to support the more stringent standard is that there are EGUs that are permitted to fire lignite—and are only firing lignite—that have demonstrated an ability to meet the more stringent standard of 1.2 lb/TBtu.

Comment: Several commenters claimed that, rather than using actual measured Hg concentrations in lignite that had been provided in the CAA section 114 request responses (and elsewhere), the EPA used Integrated Planning Model (IPM) data to assign inlet Hg concentrations to various lignite-fired EGUs. Some commenters asserted that the actual concentration of Hg in lignite is higher than those assumed by the EPA and that there is considerable variability in the concentration of Hg in the lignite used in these plants. As a result, the commenters claimed, the percent Hg capture needed to achieve the proposed 1.2 lb/TBtu emission standard would be higher than that assumed by the EPA in the 2023 Proposal.

---

[67] Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants. Andover Technology Partners. August 19, 2021. Document ID No. EPA–HQ–OAR–2018–0794–4583.

[68] *https://www.eia.gov/electricity/data/eia923/.*

Response: In the 2023 Proposal, the EPA assumed a Hg inlet concentration (*i.e.,* concentration of Hg in the fuel) that reflected the maximum Hg content of the range of feedstock coals that the EPA assumes is available to each of the plants in the IPM. In response to comments received on the proposal, the EPA has modified the Hg inlet concentration assumptions for each unit to reflect measured Hg concentrations in lignite using information provided by commenters and other sources, including measured Hg concentrations in fuel samples from the Agency's 1998 Information Collection Request (1998 ICR). This is explained in additional detail below in section V.D.1. and in a supporting technical memorandum titled *1998 ICR Coal Data Analysis Summary of Findings.* However, this adjustment in the assumed concentration of Hg in the various fuels did not change the EPA's overall conclusion that there are available controls and improved methods of operation that will allow lignite-fired EGUs to meet a more stringent Hg emission standard of 1.2 lb/TBtu.

Comment: Some commenters claimed that the Agency failed to account for compositional differences in lignite as compared to those of other types of coal—especially in comparison to subbituminous coal.

Response: The EPA disagrees with these commenters. In the 2023 Proposal, the EPA emphasized the similarities between lignite and subbituminous coal—especially regarding the fuel properties that most impact the control of Hg. The EPA noted that lignite and subbituminous coal are both low rank coals with low halogen content and explained that the halogen content of the coal—especially chlorine—strongly influences the oxidation state of Hg in the flue gas stream and, thereby, directly influences the ability to capture and contain the Hg before it is emitted into the atmosphere. The EPA further noted that the fly ashes from lignite and subbituminous coals tend to be more alkaline (relative to that from bituminous coal) due to the lower amounts of sulfur and halogen and to the presence of a more alkaline and reactive (non-glassy) form of calcium in the ash. Due to the natural alkalinity, subbituminous and lignite fly ashes can effectively neutralize the limited free halogen in the flue gas and prevent oxidation of gaseous elemental Hg vapor (Hg^0). This lack of free halogen in the flue gas challenges the control of Hg from both subbituminous coal-fired EGUs and lignite-fired EGUs as compared to the Hg control of EGUs firing bituminous coal. The EPA noted in the 2023 Proposal, however, that control strategies and control technologies have been developed and utilized to introduce halogens to the flue gas stream, and that EGUs firing subbituminous coals have been able to meet (and oftentimes emit at emission rates that are considerably lower than) the 1.2 lb/TBtu emission standard in the 2012 MATS Final Rule. Therefore, while the EPA acknowledges that there are differences in the composition of the various coal types, there are available control technologies that allow EGUs firing any of those coal types to achieve an emission standard of 1.2 lb/TBtu. The EPA further notes that North Dakota and Texas lignites are much more similar in composition and in other properties to Wyoming subbituminous coal than either coal type is to eastern bituminous coal. Both lignite and subbituminous coal are lower heating value fuels with high alkaline content and low natural halogen. In contrast, eastern bituminous coals are higher heating value fuels with high natural halogen content and low alkalinity. But while Wyoming subbituminous coal is much more similar to lignite than it is to eastern bituminous coals, EGUs firing subbituminous coal must meet the same Hg emission standard (1.2 lb/TBtu) as EGUs firing bituminous coal. The EPA further acknowledges the differences in sulfur content between subbituminous coal and lignite and its impact is discussed in the following comment summary and response.

Comment: Some commenters claimed that the EPA did not account for the impacts of the higher sulfur content of lignite as compared to that of subbituminous coal, and that such higher sulfur content leads to the presence of additional SO_3 in the flue gas stream. The commenters noted that the presence of SO_3 is known to negatively impact the effectiveness of activated carbon for Hg control.

Response: The EPA agrees with the commenters that the Agency did not fully address the potential impacts of SO_3 on the control of Hg from lignite-fired EGUs in the 2023 Proposal. However, in response to these comments, the EPA conducted a more robust evaluation of the impact of SO_3 in the flue gas of lignite-fired EGU and determined that it does not affect our previous determination that there are control technologies and methods of operation that are available to EGUs firing lignite that would allow them to meet a Hg emission standard of 1.2 lb/TBtu—the same emission standard that must be met by EGUs firing all other types of coal. As discussed in more detail below, the EPA determined that there are commercially available advanced ''SO_3 tolerant'' Hg sorbents and other technologies that are specifically designed for Hg capture in high SO_3 flue gas environments. These advanced sorbents allow for capture of Hg in the presence of SO_3 and other challenging flue gas environments at costs that are consistent with the use of conventional pre-treated activated carbon sorbents.[69] The EPA has considered the additional information regarding the role of flue gas SO_3 on Hg control and the information on the availability of advanced ''SO_3 tolerant'' Hg sorbents and other control technologies and finds that this new information does not change the Agency's determination that a Hg emission standard of 1.2 lb/TBtu is achievable for lignite-fired EGUs.

Comment: Several commenters noted the EPA made improper assumptions to reach the conclusion that the revised Hg emissions limit is achievable and claimed that none of the 22 lignite-fired EGUs are currently in compliance with the proposed 1.2 lb/TBtu Hg emission standard and that the EPA has not shown that any EGU that is firing lignite has demonstrated that it can meet the proposed Hg emission standard.

Response: The EPA disagrees with commenters' assertion and maintains that the Agency properly determined that the proposed, more stringent Hg emission standard can be achieved, cost-effectively, using available control technologies and improved methods of operation. Further, the EPA notes that, contrary to commenters' claim, there are, in fact, EGUs firing lignite that have demonstrated an ability to meet the more stringent 1.2 lb/TBtu Hg emission standard. Twin Oaks units 1 and 2 are lignite-fired EGUs operated by Major Oak Power, LLC, and located in Robertson County, Texas. In the 2023 Proposal (see 88 FR 24879 table 8), we showed that 2021 average Hg emission rates for Twin Oaks 1 and 2 (listed in the table as Major Oak #1 and Major Oak #2) were 1.24 lb/TBtu and 1.31 lb/TBtu, respectively, which are emission rates that are just slightly above the final emission limit. Both units at Major Oak have qualified for LEE status for Hg. To demonstrate LEE status for Hg an EGU owner/operator must conduct an initial EPA Method 30B test over 30 days and follow the calculation procedures in the final rule to document a potential to emit (PTE) that is less than 10 percent of the applicable Hg emissions limit (for

---

[69] See Tables 8 and 9 from ''Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants'', Andover Technology Partners (August 2021); available in the rulemaking docket at Docket ID: EPA–HQ–OAR–2018–4583.

lignite-fired EGUs this would be a rate of 0.40 lb/TBtu) *or* less than 29 lb of Hg per year. If an EGU qualifies as a LEE for Hg, then the owner/operator must conduct subsequent performance tests on an annual basis to demonstrate that the unit continues to qualify. In their most recent compliance reports[70] (dated November 14, 2023), Major Oak Power, LLC, summarized the performance testing. Between August 1 and September 19, 2023, Major Oak Power, LLC, personnel performed a series of performance tests for Hg on Twin Oaks units 1 and 2. The average Hg emissions rate for the 30-boiler operating day performance tests was 1.1 lb/TBtu for unit 1 and 0.91 lb/TBtu for unit 2. The EGUs demonstrated LEE status by showing that each of the units has a Hg PTE of less than 29 lb per year. Further, in LEE demonstration testing for the previous year (2022), Major Oak Power, LLC, found that the average Hg emissions rate for the 30-boiler operating day performance test was 0.86 lb/TBtu for unit 1 and 0.63 lb/TBtu for unit 2.

In the 2023 LEE demonstration compliance report, Twin Oaks unit 1 was described as a fluidized bed boiler that combusts lignite and is equipped with fluidized bed limestone (FBL) injection for SO_2 control, selective non-catalytic reduction (SNCR) for control of nitrogen oxides (NO_X), and a baghouse (FF) for PM control. In addition, unit 1 has an untreated activated carbon injection (UPAC) system as well as a brominated powdered activated carbon (BPAC) injection system for absorbing vapor phase Hg in the effluent upstream of the baghouse. Twin Oaks unit 2 is described in the same way.

Similarly, Red Hills units 1 and 2, located in Choctaw County, Mississippi,[71] also demonstrated 2021 annual emission rates while firing lignite from an adjacent mine of 1.33 lb/TBtu and 1.35 lb/TBtu, which are reasonably close to the proposed Hg emission standard of 1.2 lb/TBtu to demonstrate achievability. In 2022, average Hg emission rates for Red Hills unit 1 and unit 2, again while firing Mississippi lignite, were 1.73 lb/TBtu and 1.75 lb/TBtu, respectively. The EPA also notes that, as shown below in table 5, lignite mined in Mississippi has the highest average Hg content—as compared to lignites mined in Texas and North Dakota.

The performance of Twin Oaks units 1 and 2 and Red Hills Generating Facility units 1 and 2 clearly demonstrate the achievability of the proposed 1.2 lb/TBtu emission standard by lignite-fired EGUs. However, even if there were no lignite-fired EGUs that are meeting (or have demonstrated an ability to meet) the more stringent Hg emission standard, that would not mean that the more stringent emission standard was not achievable. Most Hg control technologies are ''dial up'' technologies—for example, sorbents or chemical additives have injection rates that can be ''dialed'' up or down to achieve a desired Hg emission rate. In response to the EPA's 2022 CAA section 114 information request, some responding owners/operators indicated that sorbent injection rates were set to maintain a Hg emission rate below the 4.0 lb/TBtu emission limit. In some instances, operators of EGUs reported that they were not injecting any Hg sorbent and were able to meet the less stringent emission standard. Most units that are permitted to meet a Hg emission standard of 4.0 lb/TBtu have no reason to ''over control'' since doing so by injecting more sorbent would increase their operating costs. So, it is unsurprising that many units that are permitted to fire lignite have reported Hg emission rates between 3.0 and 4.0 lb/TBtu.

While most lignite-fired EGUs have no reason to ''over control'' beyond their permitted emission standard of 4.0 lb/TBtu, Twin Oaks units 1 and 2 do have such motivation. As mentioned earlier, those sources have achieved LEE status for Hg (by demonstrating a Hg PTE of less than 29 lb/yr) and they must conduct annual performance tests to show that the units continue to qualify. According to calculations provided in their annual LEE certification, to maintain LEE status, the units could emit no more than 1.79 lb/TBtu and maintain a PTE of less than 29 lb/TBtu. So, the facilities are motivated to over control beyond 1.79 lb/TBtu (which, as described earlier in this preamble, they have consistently done).

Comment: To highlight the difference in the ability of lignite-fired and subbituminous-fired EGUs to control Hg, one commenter created a table to show a comparison between the Big Stone Plant (an EGU located in South Dakota firing subbituminous coal) and Coyote Station (an EGU located in North Dakota firing lignite). Additionally, the commenter included figures showing rolling 30-boiler operating day average Hg emission rates and the daily average ACI feed rates for Big Stone and Coyote EGUs for years 2021–2022. Their table showed that Big Stone and Coyote are similarly configured plants that utilize the same halogenated ACI for Hg control. The commenters said, however, that Coyote Station's average sorbent feed rate on a lb per million actual cubic feet (lb/MMacf) basis is more than three times higher than that for Big Stone, yet Coyote Station's average Hg emissions on a lb/TBtu basis are more than five times higher than Big Stone.

Response: The EPA agrees that the Big Stone and Coyote Station units referenced by the commenter are similarly sized and configured EGUs, with the Big Stone unit in South Dakota firing subbituminous coal and the Coyote Station unit in North Dakota firing lignite. However, there are several features of the respective units that can have an impact on the control of Hg. First, and perhaps the most significant, the Big Stone unit has a selective catalytic reduction (SCR) system installed for control of NOx. The presence of an SCR is known to enhance the control of Hg—especially in the presence of chemical additives. The Coyote Station EGU does not have an installed SCR. Further, both EGUs have a dry FGD scrubber and FF baghouse installed for SO_2/acid gas and fPM control. The average sulfur content of North Dakota lignite is approximately 2.5 times greater than that of Wyoming subbituminous coal. However, the average SO_2 emissions from the Coyote Station EGU (0.89 lb/MMBtu) were approximately 10 times higher than the SO_2 emissions from the Big Stone EGU (0.09 lb/MMBtu). The Big Stone dry scrubber/FF was installed in 2015; while the dry scrubber/FF at Coyote Station was installed in 1981—approximately 31 years earlier. So, considering the presence of an SCR—which is known to enhance Hg control—and newer and better performing downstream controls, it is unsurprising that there are differences in the control of Hg at the two EGUs. In addition, since the Coyote Station has been subject to a Hg emission standard of 4.0 lb/TBtu, there would be no reason for the operators to further optimize its control system to achieve a lower emission rate. And, as numerous commenters noted, the Hg content of North Dakota is higher than that of Wyoming subbituminous coal.

Comment: Some commenters claimed that the EPA has not adequately justified a reversal in the previous policy to establish a separate subcategory for lignite-fired EGUs.

---

[70] See page 1–1 of the 2023 Compliance Reports for Twin Oaks 1 and 2 available in the rulemaking docket at EPA–HQ–OAR–2018–0794.

[71] Choctaw Generation LP leases and operates the Red Hills Power Plant. The plant supplies electricity to the Tennessee Valley Authority (TVA) under a 30-year power purchase agreement. The lignite output from the adjacent mine is 100 percent dedicated to the power plant. *https://www.purenergyllc.com/projects/choctaw-generation-lp-red-hills-power-plant/#page-content.*

Response: In developing the 2012 Final MATS Rule, the EPA examined the EGUs in the top performing 12 percent of sources for which the Agency had Hg emissions data. In examining that data, the EPA observed that there were no lignite-fired EGUs among the top performing 12 percent of sources for Hg emissions. The EPA then determined that this indicated that there is a difference in the Hg emissions from lignite-fired EGUs when compared to the Hg emissions from EGUs firing other coal types (that were represented among the top performing 12 percent). That determination was not based on any unique property or characteristic of lignite—only on the observation that there were no lignite-fired EGUs among the best performing 12 percent of sources (for which the EPA had Hg emissions data). In fact, as noted in the preamble for the 2012 Final MATS Rule, the EPA ''believed at proposal that the boiler size was the cause of the different Hg emissions characteristics.'' See 77 FR 9378.

The EPA ultimately concluded that it is appropriate to continue to base the subcategory definition, at least in part, on whether the EGUs were ''designed to burn and, in fact, did burn low rank-virgin coal'' (*i.e.,* lignite), but that it is not appropriate to continue to use the boiler size criteria (*i.e.,* the height-to-depth ratio). However, the EPA ultimately finalized the ''unit designed for low rank virgin coal'' subcategory based on the characteristics of the EGU—not on the properties of the fuel. ''We are finalizing that the EGU is considered to be in the ''unit designed for low rank virgin coal'' subcategory if the EGU: (1) meets the final definitions of ''fossil fuel-fired'' and ''coal-fired electric utility steam generating unit;'' and (2) is designed to burn and is burning non-agglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) and that is constructed and operates at or near the mine that produces such coal.'' See 77 FR 9369.

While, in the 2012 MATS Final Rule, the EPA based the lignite-fired EGU subcategory on the design and operation of the EGUs, the EPA did not attribute the observed differences in Hg emissions to any unique characteristic(s) of lignite. As the EPA clearly noted in the 2023 Proposal, there are, in fact, characteristics of lignite that make the control of Hg more challenging. These include the low natural halogen content, the high alkalinity of the fly ash, the sulfur content, the relatively higher Hg content, and the relatively higher variability of Hg content. However, as the EPA has explained, these characteristics that make the control of Hg more challenging are also found in non-lignite fuels. Subbituminous coals also have low natural halogen content and high fly ash alkalinity. Eastern and central bituminous coals also have high sulfur content. Bituminous and anthracitic waste coals (coal refuse) have very high and variable Hg content. EGUs firing any of these non-lignite coals have been subject to—and have demonstrated compliance with—the more stringent Hg emission standard of 1.2 lb/TBtu.

The EPA has found it appropriate to reverse the previous policy because the decision to subcategorize ''units designed for low rank virgin coal'' in the 2012 MATS Final Rule was based a determination that there were differences in Hg emissions from lignite-fired EGUs as compared to EGUs firing non-lignite coals. That perceived difference was based on an observation that there were no lignite-fired EGUs in the top performing 12 percent of EGUs for which the Agency had Hg emissions data and on an assumption that the perceived difference in emissions was somehow related to the design and operation of the EGU. The EPA is unaware of any distinguishing features of EGUs that were designed to burn lignite that would impact the emissions of Hg. Further, the EPA does not now view the fact that there were no lignite-fired EGUs in the population of the best-performing 12 percent of EGUs for which the Agency had Hg emissions data to represent a ''difference in emissions.''

But, on re-examination of the data, the EPA has concluded that the Hg emissions from the 2010 ICR for the lignite-fired EGUs were not clearly distinctive from the Hg emissions from EGUs firing non-lignite coal. In setting the emission standards for the 2012 MATS Final Rule, the EPA had available and useable Hg emissions data from nearly 400 coal-fired EGUs (out of the 1,091 total coal-fired EGUs operating at that time). However, the EPA only had available and useable data from nine lignite-fired EGUs with reported floor Hg emissions ranging from 1.0 to 10.9 lb/TBtu. But these were not outlier emission rates. EGUs firing bituminous coal reported Hg emissions as high as 30.0 lb/TBtu; and those firing subbituminous coal reported Hg emissions as high as 9.2 lb/TBtu.

D. What is the rationale for our final approach and decisions for the lignite-fired EGU Hg standard?

In the 2023 Proposal, the EPA proposed to determine that there are developments in available control technologies and methods of operation that would allow lignite-fired EGUs to meet a more stringent Hg emission standard of 1.2 lb/TBtu—the same Hg emission standard that must be met by coal-fired EGUs firing non-lignite coals (*e.g.,* anthracite, bituminous coal, subbituminous coal, coal refuse, *etc.*). After consideration of public comments received on the proposed revision of the Hg emission standard, the EPA continues to find that the evidence supports that there are commercially available control technologies and improved methods of operation that allow lignite-fired EGUs to meet the more stringent Hg emission standard that the EPA proposed. As noted above, lignite-fired EGUs also comprise some of the largest sources of Hg emissions within this source category and are responsible for a disproportionate share of Hg emissions relative to their generation. While previous EPA assessments have shown that current modeled exposures [of Hg] are well below the reference dose (RfD), we conclude that further reductions of Hg emissions from lignite-fired EGUs covered in this final action should further reduce exposures including for the subsistence fisher sub-population. This anticipated exposure is of particular importance to children, infants, and the developing fetus given the developmental neurotoxicity of Hg. Therefore, in this final action, the EPA is revising the Hg emission standard for lignite-fired EGUs from the 4.0 lb/TBtu standard that was finalized in the 2012 MATS Final Rule to the more stringent emission standard of 1.2 lb/TBtu, as proposed. The rationale for the Agency's final determination is provided below.

In this final rule, the EPA is also reaching a different conclusion from the 2020 Technology Review with respect to the Hg emission standard for lignite-fired EGUs. As discussed in section II.D. above, the 2020 Technology Review did not evaluate the current performance of emission reduction control equipment and strategies at existing lignite-fired EGUs. Nor did the 2020 Technology Review specifically address the discrepancy between Hg emitted from lignite-fired EGUs and non-lignite coal-fired EGUs or consider the improved performance of injected sorbents or chemical additives, or the development of SO_3-tolerant sorbents. Based on the EPA's review in this rulemaking which considered such information, the Agency determined that there are available control technologies that allow EGUs firing lignite to achieve an emission standard of 1.2 lb/TBtu, consistent with the Hg emission standard required for non-lignite coal-fired EGUs, which the EPA is finalizing pursuant to its CAA section 112(d)(6) authority.

1. Mercury Content of Lignite

For analyses supporting the proposal, the EPA assumed ''Hg Inlet'' levels (*i.e.,* Hg concentration in inlet fuel) that are consistent with those assumed in the Agency's power sector model (IPM) and then adjusted accordingly to reflect the 2021 fuel blend for each unit. Several commenters indicated that the Hg content of lignite fuels is much higher and has greater variability than the EPA assumed.

To support the development of the NESHAP for the Coal- and Oil-Fired EGU source category, the Agency conducted a 2-year data collection effort which was initiated in 1998 and completed in 2000 (1998 ICR). The ICR had three main components: (1) identifying all coal-fired units owned and operated by publicly owned utility companies, federal power agencies, rural electric cooperatives, and investor-owned utility generating companies; (2) obtaining accurate information on the amount of Hg contained in the as-fired coal used by each electric utility steam generating unit with a capacity greater than 25 MW electric, as well as accurate information on the total amount of coal burned by each such unit; and (3) obtaining data by coal sampling and stack testing at selected units to characterize Hg reductions from representative unit configurations.

The ICR captured the origin of the coal burned, and thus provided a pathway for linking emission properties to coal basins. The 1998–2000 ICR resulted in more than 40,000 data points indicating the coal type, sulfur content, Hg content, ash content, chlorine content, and other characteristics of coal burned at coal-fired utility boilers greater than 25 MW.

Annual fuel characteristics and delivery data reported on EIA form 923 also provide continual data points on coal heat content, sulfur content, and geographic origin, which are used as a check against characteristics initially identified through the 1998 ICR.

For this final rule, the EPA re-evaluated the 1998 ICR data.[72] Specifically, the EPA evaluated the coal Hg data to characterize the Hg content of lignite, which is mined in North Dakota, Texas, and Mississippi, and to characterize by seam and by coal delivered to a specific plant.[73] The results are presented as a range of Hg content of the lignites as well as the mean and median Hg content. The EPA also compared the fuel characteristics of lignites mined in North Dakota, Texas, and Mississippi against coals mined in Wyoming (subbituminous coal), Pennsylvania (mostly upper Appalachian bituminous coal), and Kentucky (mostly lower Appalachian bituminous coal). The Agency also included in the re-evaluation, coal analyses that were submitted in public comments by North American Coal (NA Coal). In addition to the Hg content, the analysis included the heating value and the sulfur, chlorine, and ash content for each coal that is characterized.

The analysis showed that lignite mined in North Dakota had a mean Hg content of 9.7 lb/TBtu, a median Hg content of 8.5 lb/TBtu, and a Hg content range of 2.2 to 62.1 lb/TBtu. Other characteristics of North Dakota lignite include an average heating value (dry basis) of 10,573 Btu/lb, an average sulfur content of 1.19 percent, an average ash content of 13.5 percent, and an average chlorine content of 133 parts per million (ppm). In response to comments on the 2023 Proposal, for analyses supporting this final action, the EPA has revised the assumed Hg content of lignite mined in North Dakota to 9.7 lb/TBtu versus the 7.81 lb/TBtu assumed in the 2023 Proposal.

Similarly, the analysis showed that lignite mined in Texas had a mean and median Hg content of 25.0 lb/TBtu and 23.8 lb/TBtu, respectively, and a Hg content range from 0.7 to 92.0 lb/TBtu. Other characteristics include an average heating value (dry basis) of 9,487 Btu/lb, an average sulfur content of 1.42 percent, an average ash content of 24.6 percent, and an average chlorine content of 233 ppm. In response to comments on the 2023 Proposal, for analyses supporting this final action, the EPA has revised the assumed Hg content of lignite mined in Texas to 25.0 lb/TBtu versus the range of 14.65 to 14.88 lb/TBtu that was assumed for the 2023 Proposal.

Lignite mined in Mississippi had the highest mean Hg content at 34.3 lb/TBtu and the second highest median Hg emissions rate, 30.1 lb/TBtu. The Hg content ranged from 3.6 to 91.2 lb/TBtu. Lignite from Mississippi had an average heating value (dry basis) of 5,049 Btu/lb and a sulfur content of 0.58 percent. In response to comments submitted on the 2023 Proposal, for analyses supporting this final action, the EPA assumed a Hg content of 34.3 lb/TBtu for lignite mined in Mississippi versus the 12.44 lb/TBtu assumed for the proposal.

The EPA 1998 ICR dataset did not contain information on lignite from Mississippi, which resulted in a smaller number of available data points (227 in Mississippi lignite versus 864 for North Dakota lignite and 943 for Texas lignite). Table 5 of this document more fully presents the characteristics of lignite from North Dakota, Texas, and Mississippi.

---

[72] Technical Support Document ''*1998 ICR Coal Data Analysis Summary of Findings*'' available in the rulemaking docket at EPA–HQ–OAR–2018–0794.

[73] In 2022, over 99 percent of all lignite was mined in North Dakota (56.2 percent), Texas (35.9 percent), and Mississippi (7.1 percent). Small amounts (less than 1 percent) of lignite were also mined in Louisiana and Montana. See Table 6. ''Coal Production and Number of Mines by State and Coal Rank'' from EIA Annual Coal Report, available at *https://www.eia.gov/coal/annual/.*

Table 5. Characteristics of Lignite mined in North Dakota, Texas, and Mississippi from the EPA 1998 ICR Dataset

	North Dakota	Texas	Mississippi
Number of data points	864	943	227
Range of Hg content (lb/TBtu)	2.2 – 62.1	0.7 – 92.0	3.6 – 91.2
Mean Hg content (lb/TBtu)	9.7	25.0	34.3
Median Hg content (lb/TBtu)	8.5	23.8	30.1
Heating value average (Btu/lb, dry)	10,573	9,486	5,049
Sulfur content average (%, dry)	1.12	1.42	0.58
Ash content average (%, dry)	13.54	24.60	N/A
Chlorine content average (ppm, dry)	133	232	N/A

Coals mined in Kentucky, Pennsylvania, and Wyoming were also analyzed for comparison. The types of coal (all non-lignite) included bituminous, bituminous-high sulfur, bituminous-low sulfur, subbituminous, anthracite, waste anthracite, waste bituminous, and petroleum coke. Bituminous coal accounted for 92 percent of the data points from Kentucky and 75 percent of the data points from Pennsylvania. Subbituminous coal accounted for 96 percent of the data points from Wyoming.

Bituminous coals from Kentucky had a mean Hg emissions content of 7.2 lb/TBtu (ranging from 0.7 to 47.4 lb/TBtu), an average heating value (dry basis) of 13,216 Btu/lb, an average sulfur content of 1.43 percent, an average ash content of 10.69 percent, and an average chlorine content of 1,086 ppm.

Bituminous coals from Pennsylvania had a mean Hg emissions rate of 14.5 lb/TBtu (ranging from 0.1 to 86.7 lb/TBtu), an average heating value (dry basis) of 13,635 Btu/lb, an average sulfur content of 1.88 percent, an average ash content of 10.56 percent, and an average chlorine content of 1,050 ppm.

Subbituminous coals from Wyoming had a mean Hg rate of 5.8 lb/TBtu, an average heating value (dry basis) of 12,008 Btu/lb, an average sulfur content of 0.44 percent, an average ash content of 7.19 percent, and an average chlorine content of 127 ppm. Table 6 of this document shows the characteristics of bituminous coal from Kentucky and Pennsylvania and subbituminous coal from Wyoming.

Table 6. Characteristics of Bituminous and Subbituminous Coals mined in Kentucky, Pennsylvania, and Wyoming from the EPA 1998 ICR Dataset

	Kentucky (Bituminous)	Pennsylvania (Bituminous)	Wyoming (Subbituminous)
Number of data points	5,340	3,072	6,467
Range of Hg content (lb/TBtu)	0.7 – 47.4	0.1 – 86.7	0.7 – 40.7
Mean Hg content (lb/TBtu)	7.2	14.5	5.8
Median Hg content (lb/TBtu)	6.7	9.7	2.4
Heating value average (Btu/lb, dry)	13,216	13,635	12,008
Sulfur content average (%, dry)	1.43	1.88	0.44
Ash content average (%, dry)	10.69	10.56	7.19
Chlorine content average (ppm, dry)	1,086	1,050	127

Several commenters claimed that one of the factors that contributes to the challenge of controlling Hg emissions from EGUs firing lignite is the variability of the Hg content in lignite. However, as can be seen in table 5 and table 6 of this document, all coal types examined by the EPA contain a variable content of Hg. The compliance demonstration requirements in the 2012 MATS Final Rule were designed to accommodate the variability of Hg in coal by requiring compliance with the respective Hg emission standards over a 30-operating-day rolling average period. When examining the Hg emissions for EGUs firing on the various coal types (including those firing Wyoming subbituminous coal, which has the lowest mean and median Hg content and the narrowest range of Hg content), daily emissions often exceed the applicable emission standard (sometimes considerably). However, averaging emissions over a rolling 30-operating-day period effectively dampens the impacts of fuel Hg content variability. For example, in figure 1 (a graph) of this document, the 2022 Hg emissions from Dave Johnston unit BW41, a unit firing subbituminous coal, are shown. The graph shows both the daily Hg emissions and the 30-operating-day rolling average Hg emissions. As can be seen in the graph, the daily Hg emissions very often exceed the 1.2 lb/TBtu emission rate; however, the 30-operating-day rolling average is consistently below the emission limit (the annual average emission rate is 0.9 lb/TBtu).

BILLING CODE 6560–50–P

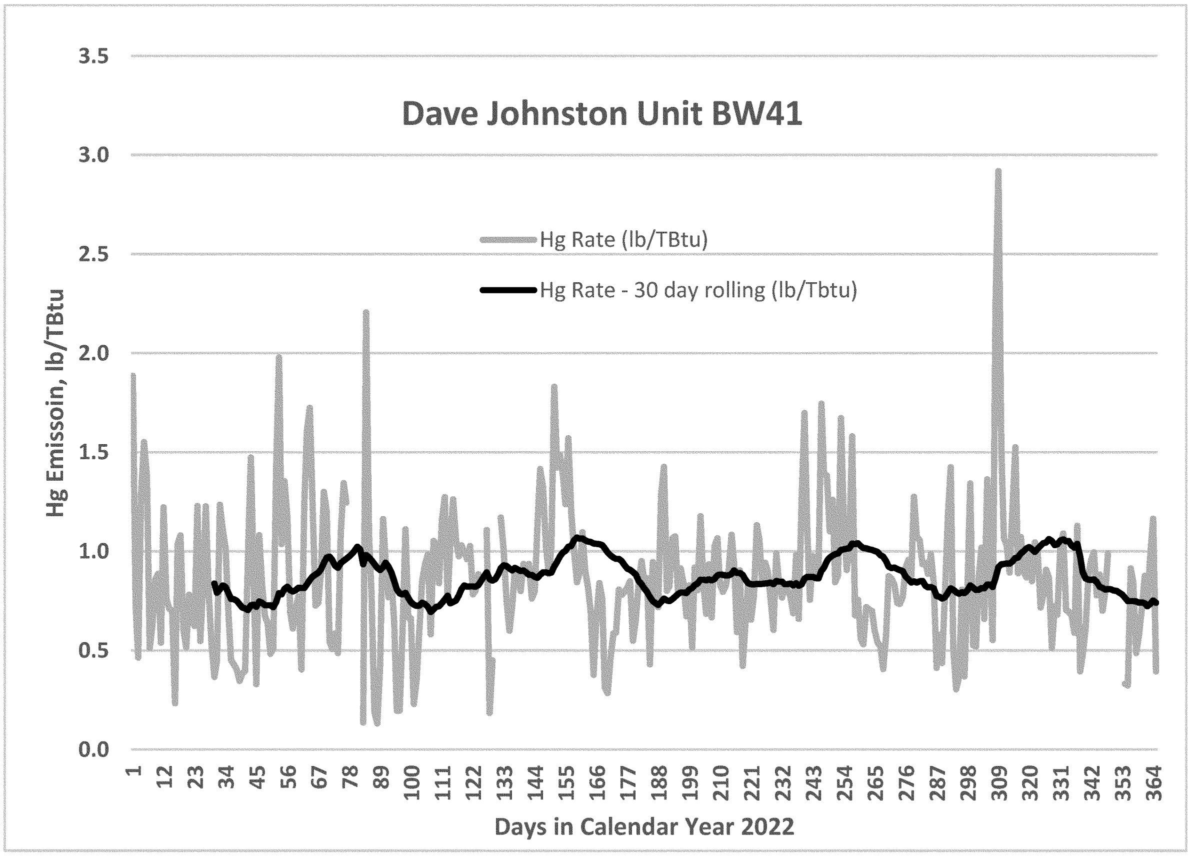


Figure 1. 2022 Daily and 30-Day Rolling Average Hg Emission Rates (lb/TBtu)

From Dave Johnston Unit BW41, a subbituminous-fired EGU in Wyoming.

A similar effect can be seen with the 2022 daily and 30-operating-day rolling average Hg emissions from Leland Olds unit 1, an EGU firing North Dakota lignite, shown in figure 2 of this document.

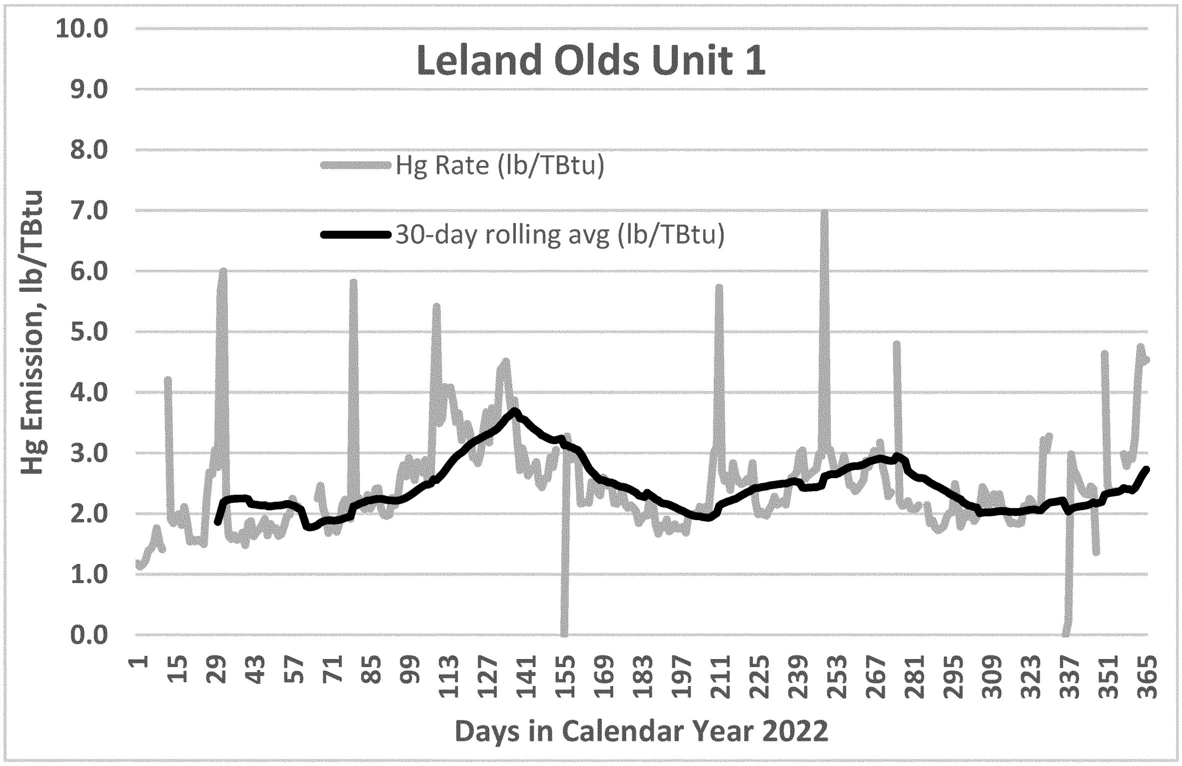


Figure 2. Daily and 30-Day Rolling Average Hg Emission Rates (lb/TBtu) from Leland Olds Unit 1, lignite-fired EGU in North Dakota.

BILLING CODE 6560–50–C

As with the EGU firing subbituminous coal, the daily Hg emissions very often exceed the emission limit (in this case 4.0 lb/TBtu); however, the 30-operating-day rolling average is consistently below the applicable emission limit (the 2022 annual average emission rate for Leland Olds unit 1 is 2.3 lb/TBtu).

2. The Impact of Halogen Content of Lignite on Hg Control

In the 2023 Proposal, the EPA explained that during combustion of coal, the Hg contained in the coal is volatilized and converted to Hg^0 vapor in the high-temperature regions of the boiler. Hg^0 vapor is difficult to capture because it is typically nonreactive and insoluble in aqueous solutions. However, under certain conditions, the Hg^0 vapor in the flue gas can be oxidized to divalent Hg (Hg^{2+}). The Hg^{2+} can bind to the surface of solid particles (*e.g.,* fly ash, injected sorbents) in the flue gas stream, often referred to as ‘‘particulate bound Hg’’ (Hg_p) and be removed in a downstream PM control device. Certain oxidized Hg compounds that are water soluble may be further removed in a downstream wet scrubber. The presence of chlorine in gas-phase equilibrium favors the formation of mercuric chloride ($HgCl_2$) at flue gas cleaning temperatures. However, Hg^0 oxidation reactions are kinetically limited as the flue gas cools, and as a result Hg may enter the flue gas cleaning device(s) as a mixture of Hg^0, Hg^{2+} compounds, and Hg_p.

This partitioning into various species of Hg has considerable influence on selection of Hg control approaches. In tables 5 and 6 of this document, the chlorine content of bituminous coals mined in Kentucky and Pennsylvania averaged 1,086 ppm and 1,050 ppm, respectively. In comparison, the average chlorine content of Wyoming subbituminous coal is 127 ppm; while the chlorine contents of lignite mined in North Dakota and Texas are 133 ppm and 232 ppm, respectively. In general, because of the presence of higher amounts of halogen (especially chlorine) in bituminous coals, most of the Hg in the flue gas from bituminous coal-fired boilers is in the form of Hg^{2+} compounds, typically $HgCl_2$, and is more easily captured in downstream control equipment. Conversely, both subbituminous coal and lignite have lower natural halogen content compared to that of bituminous coals, and the Hg in the flue gas from boilers firing those fuels tends to be in the form of Hg^0 and is more challenging to control in downstream control equipment.

While some bituminous coal-fired EGUs require the use of additional Hg-specific control technology, such as injection of a sorbent or chemical additive, to supplement the control that these units already achieve from criteria pollutant control equipment, these Hg-specific control technologies are often required as part of the Hg emission reduction strategy at EGUs that are firing subbituminous coal or lignite. As described above, the Hg in the flue gas for EGUs firing subbituminous coal or lignite tends to be in the nonreactive Hg^0 vapor phase due to lack of available free halogen to promote the oxidation reaction. To alleviate this challenge, activated carbon and other sorbent providers and control technology vendors have developed methods to introduce halogen into the flue gas to improve the control of Hg emissions from EGUs firing subbituminous coal and lignite. This is primarily through the injection of pre-halogenated (often pre-brominated) activated carbon sorbents or through the injections of halogen-containing chemical additives along with conventional sorbents. In the

2022 CAA section 114 information collection, almost all the lignite-fired units reported use of some sort of halogen additive or injection as part of their Hg control strategy by using refined coal (which typically has added halogen), bromide or chloride chemical additives, pre-halogenated sorbents, and/or oxidizing agents. Again, low chlorine content in the fuel is a challenge that is faced by EGUs firing either subbituminous coals or lignite, and EGUs firing subbituminous coal have been subject to a Hg emission standard of 1.2 lb/TBtu since the MATS rule was finalized in 2012.

3. The Impact of SO_3 on Hg Control

Some commenters noted that the EPA did not account for the impacts of the higher sulfur content of lignite as compared to that of subbituminous coal, and that such higher sulfur content leads to the presence of additional SO_3 in the flue gas stream. As shown in table 5 and table 6 of this document, while the halogen content of subbituminous coal and lignite is similar, the average sulfur content of lignite is more like that of bituminous coal mined in Kentucky and Pennsylvania.

During combustion, most of the sulfur in coal is oxidized into SO_2, and only a small portion is further oxidized to SO_3 in the boiler. In response to environmental requirements, many EGUs have installed SCR systems for NO_X control and FGD systems for SO_2 control. One potential consequence of an SCR retrofit is an increase in the amount of SO_3 in the flue gas downstream of the SCR due to catalytic oxidation of SO_2. Fly ash and condensed SO_3 are the major components of flue gas that contribute to the opacity of a coal plant's stack emissions and the potential to create a visible sulfuric acid ''blue plume.'' In addition, higher SO_3 levels can adversely affect many aspects of plant operation and performance, including corrosion of downstream equipment and fouling of the air preheater (APH). This is primarily an issue faced by EGUs firing bituminous coal. EGUs fueled by subbituminous coal and lignite do not typically have the same problem with blue plume formation. Of the EGUs that are designed to fire lignite, only Oak Grove units 1 and 2, located in Texas, have an installed SCR for NO_X control. Several lignite-fired EGUs utilize SNCR systems for NO_X control, which are less effective for NO_X control as compared to SCR systems. Several commenters claimed that SCR is not a viable NO_X control technology for EGUs firing North Dakota lignite because of catalyst fouling from the high sodium content of the fuel and resulting fly ash.

Coal fly ash is typically classified as acidic (pH less than 7.0), mildly alkaline (pH greater than 7.0 to 9.0), or strongly alkaline (pH greater than 9.0). The pH of the fly ash is usually determined by the calcium/sulfur ratio and the amount of halogen. The ash from bituminous coals tends to be acidic due to the relatively higher sulfur and halogen content and the glassy (nonreactive) nature of the calcium present in the ash. Conversely, the ash from subbituminous coals and lignite tends to be more alkaline due to the lower amounts of sulfur and halogen and a more alkaline and reactive (non-glassy) form of calcium—and, as noted by commenters—the presence of sodium compounds in the ash. The natural alkalinity of the subbituminous and lignite fly ash may effectively neutralize the limited free halogen in the flue gas and prevent oxidation of the Hg^0. However, the natural alkalinity also helps to minimize the impact of SO_3, because a common control strategy for SO_3 is the injection of alkaline sorbents (dry sorbent injection, DSI).

Still, as commenters correctly noted, the presence of SO_3 in the flue gas stream is also known to negatively impact the effectiveness of sorbent injection for Hg control. This impact has been known for some time, and control technology researchers and vendors have developed effective controls and strategies to minimize the impact of SO_3.[74] As noted above, coal-fired EGUs utilizing bituminous coal—which also experience significant rates of SO_3 formation in the flue gas stream—have also successfully demonstrated the application of Hg control technologies to meet a standard of 1.2 lb/TBtu.

The AECOM patented SBS Injection™ (''sodium-based solution'') technology has been developed for control of SO_3, and co-control of Hg has also been demonstrated. A sodium-based solution is injected into the flue gas, typically ahead of the APH or, if present, the SCR. By removing SO_3 prior to these devices, many of the adverse effects of SO_3 can be successfully mitigated. AECOM has more recently introduced their patented HBS Injection™ technology for effective Hg oxidation and control.[75] This new process injects halogen salt solutions into the flue gas, which react in-situ to form halogen species that effectively oxidize Hg. The HBS Injection™ can be co-injected with the SBS Injection™ for effective SO_3 control and Hg oxidation/control.

Other vendors also offer technologies to mitigate the impact of SO_3 on Hg control from coal combustion flue gas streams. For example, Calgon Carbon offers their ''sulfur tolerant'' Fluepac ST, which is a brominated powdered activated carbon specially formulated to enhance Hg capture in flue gas treatment applications with elevated levels of SO_3.[76] In testing in a bituminous coal combustion flue gas stream containing greater than 10 ppm SO_3, the Fluepac ST was able to achieve greater than 90 percent Hg control at injection rates of a third or less as compared to injection rates using the standard brominated sorbent.

Babcock & Wilcox (B&W) offers dry sorbent injection systems that remove SO_3 before the point of activated carbon sorbent injection to mitigate the impact of SO_3.[77] Midwest Energy Emissions Corporation (ME_2C) offers ''high-grade sorbent enhancement additives—injected into the boiler in minimal amounts'' that work in conjunction with proprietary sorbent products to ensure maximum Hg capture. ME_2C claims that their Hg control additives and proprietary sorbent products are ''high-sulfur-tolerant and SO_3-tolerant sorbents.'' [78]

Cabot Norit Activated Carbon is the largest producer of powdered activated carbon worldwide.[79] Cabot Norit offers different grades of their DARCO® powdered activated carbon (PAC) for Hg removal at power plants. These grades include non-impregnated PAC which are ideal when most of the Hg is in the oxidized state; impregnated PAC for removing oxidized and Hg^0 from flue gas; special impregnated PAC used in conjunction with DSI systems (for control of acid gases); and special impregnated ''sulfur resistant'' PAC for flue gases that contains higher concentrations of acidic gases like SO_3.

---

[74] The mention of specific products by name does not imply endorsement by the EPA. The EPA does not endorse or promote any particular control technology. The EPA mentions specific product names here to emphasize the broad range of products and vendors offering sulfur tolerant Hg control technologies.

[75] *https://www.aecom.com/wp-content/uploads/2019/07/10_EUEC_P_PT_Brochure_HBS_InjectionTechnology_20160226_singles.pdf.*

[76] *https://www.calgoncarbon.com/app/uploads/DS-FLUEST15-EIN-E1.pdf.*

[77] *https://www.babcock.com/assets/PDF-Downloads/Emissions-Control/E101-3200-Mercury-and-HAPs-Emissions-Control-Brochure-Babcock-Wilcox.pdf.*

[78] ME2C 2016 Corporate Brochure, available in the rulemaking docket at EPA–HQ–OAR–2018–0794.

[79] *https://norit.com/application/power-steel-cement/power-plants.*

Similarly, ADA–ES offers FastPAC™ Platinum 80,[80] an activated carbon sorbent that was specifically engineered for SO_3 tolerance and for use in applications where SO_3 levels are high. So, owner/operators of lignite-fired EGUs can choose from a range of technologies and technology providers that offer Hg control options in the presence of SO_3. The EPA also notes that SO_3 is more often an issue with EGUs firing eastern bituminous coal—as those coals typically have higher sulfur content and lower ash alkalinity. Those bituminous coal-fired EGUs are subject to—and have demonstrated compliance with—an emission standard of 1.2 lb/TBtu.

4. Cost Considerations for the More Stringent Hg Emission Standard

From the 2022 CAA section 114 information survey, most lignite-fired EGUs utilized a control strategy that included sorbent injection coupled with chemical additives (usually halogens). In the beyond-the-floor analysis in the 2012 MATS Final Rule, we noted that the results from various demonstration projects suggested that greater than 90 percent Hg control can be achieved at lignite-fired units using brominated activated carbon sorbents at an injection rate of 2.0 lb/MMacf (*i.e.,* 2.0 pounds of sorbent injected per million actual cubic feet of flue gas) for units with installed FFs for PM control and at an injection rate of 3.0 lb/MMacf for units with installed ESPs for PM control. As shown in table 7 of this document, all units (in 2022) would have needed to control their Hg emissions to 95 percent or less to meet an emission standard of 1.2 lb/TBtu. Based on this, we expect that the units could meet the final, more stringent, emission standard of 1.2 lb/TBtu by utilizing brominated activated carbon at the injection rates suggested in the beyond-the-floor memorandum from the 2012 MATS Final Rule.

BILLING CODE 6560–50–P

---

[80] *https://www.advancedemissionssolutions.com/ADES-Investors/ada-products-and-services/default.aspx.*

Table 7. Measured Hg Emissions and Estimated Control Performance of Lignite-Fired EGUs in 2022

EGU	Estimated 2022 Hg Inlet[81] (lb/TBtu)	Estimated Hg Control (%) at 4.0 lb/TBtu	Estimated Hg Control (%) at 1.2 lb/TBtu	2022 Measured Hg Emissions (lb/TBtu)	Estimated 2022 Hg Control (%)
North Dakota EGUs					
Antelope Valley 1	11.2	64.4	89.3	3.03	73.0
Antelope Valley 2	11.2	64.4	89.3	3.00	73.3
Coal Creek 1	9.7	58.7	87.6	3.43	64.6
Coal Creek 2	9.7	58.7	87.6	3.87	60.1
Coyote 1	9.7	58.6	87.6	2.28	76.4
Leland Olds 1	11.3	64.5	87.6	2.34	79.3
Leland Olds 2	11.3	64.5	87.6	3.10	72.5
Milton R Young 1	9.7	58.6	87.6	3.02	68.8
Milton R Young 2	9.7	58.6	87.6	3.00	69.0
Spiritwood Station 1	9.2	56.5	87.0	2.14	76.8
Texas and Mississippi EGUs					
Limestone 1*	5.8	30.7	79.2	0.78	86.5
Limestone 2*	5.8	30.7	79.2	0.85	85.3
Major Oak Power 1	24.9	84.0	95.2	0.86	96.5
Major Oak Power 2	24.9	84.0	95.2	0.63	97.5
Martin Lake 1*	5.8	31.0	79.3	1.53	73.6
Martin Lake 2*	5.8	31.0	79.3	2.50	56.9
Martin Lake 3*	5.8	31.0	79.3	2.36	59.3
Oak Grove 1	24.8	83.9	95.2	2.53	89.8
Oak Grove 2	24.8	83.9	95.2	2.23	91.0
San Miguel 1	28.9	86.2	95.9	3.03	89.5
Red Hills 1	22.9	82.6	94.8	1.73	92.5
Red Hills 2	22.9	82.6	94.8	1.75	92.4

* These units, which are permitted to fire lignite, utilized primarily subbituminous coal in 2022.

BILLING CODE 6560–50–C

To determinethe cost effectiveness of that strategy, we calculated the cost per lb of Hg controlled for a model 800 MW lignite-fired EGU, as described in the 2024 Technical Memo. We calculated the cost of injecting brominated activated carbon sorbent at injection rates suggested in the beyond-the-floor memorandum from the 2012 MATS Final Rule (*i.e.,* 2.0 lb/MMacf and 3.0 lb/MMacf) and at a larger injection rate of 5.0 lb/MMacf to achieve an emission rate of 1.2 lb/TBtu. We also calculated the incremental cost to meet the more stringent emission rate of 1.2 lb/TBtu versus the cost to meet an emission rate of 4.0 lb/TBtu using non-brominated activated carbon sorbent at an emission rate of 2.5 lb/MMacf. For an 800 MW lignite-fired EGU, the cost effectiveness of using the brominated carbon sorbent at an injection rate of 3.0 lb/MMacf was $3,050 per lb of Hg removed while the incremental cost effectiveness was $10,895 per incremental lb of Hg removed at a brominated activated carbon injection rate of 3.0 lb/MMacf. The cost effectiveness of using the brominated carbon sorbent at an injection rate of 5.0 lb/MMacf was $5,083 per lb of Hg removed while the incremental cost effectiveness was $28,176 per incremental lb of Hg removed. The actual cost effectiveness is likely lower than either of these estimates as it is unlikely that sources will need to inject brominated activated carbon sorbent at rates as high as 5.0 lb/MMacf (from the 2022 CAA section 114 information collection, the Oak Grove units were injecting less than 0.5 lb/MMacf) and is either well below or reasonably consistent with the cost effectiveness that the EPA has found to

---

[81] Estimated Hg inlet values are based on fuel use data from EIA Form 923 and assumed Hg content of coals as shown in Table 5 and Table 6 in this preamble.

be acceptable in previous rulemakings for Hg controls.[82]

In addition to cost effectiveness, the EPA finds that the revised Hg emission standard for lignite-fired units appropriately considers the costs of controls, both total costs and as a fraction of total revenues, along with other factors that the EPA analyzed pursuant to its CAA section 112(d)(6) authority. Similar to the revised fPM emission standard (as a surrogate for non-Hg HAP metals) discussed in section IV. of this preamble, the EPA anticipates that the total costs of controls (which consists of small annual incremental operating costs) to comply with the revised Hg emission standard will be a small fraction of the total revenues for the impacted lignite-fired units. The EPA expects that sources will be able to meet the revised emission standard using existing controls (*e.g.,* using existing sorbent injection equipment), and that significant additional capital investment is unlikely. If site-specific conditions necessitate minor capital improvements to the ACI control technology, it is important to note that any incremental capital would be small relative to ongoing sorbent costs accounted for in this analysis. Further, in addition to the EPA finding that costs are reasonable for the revised Hg standard for lignite-fired EGUs, the revised standard will also bring these higher emitting sources of Hg emission in line with Hg emission rates that are achieved by non-lignite-fired EGUs. As mentioned earlier in this preamble, in 2021, lignite-fired EGUs were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs while generating about 7 percent of total megawatt-hours.

Despite the known differences in the quality and composition of the various coal types, the EPA can find no compelling reasons why EGUs that are firing lignite cannot meet the same emission limit as EGUs that are firing other types of coal (*e.g.,* eastern and western bituminous coal, subbituminous coal, and anthracitic and bituminous waste coal). Each of the coal types/ranks has unique compositions and properties. Low halogen content in coal is known to make Hg capture more challenging. But, both lignites and subbituminous coals have low halogen content with higher alkaline content. Lignites tend to have average higher Hg content than subbituminous and bituminous coals—especially lignites mined in Mississippi and Texas. However, waste coals (anthracitic and bituminous coal refuse) tend to have the highest average Hg content. Lignites tend to have higher sulfur content than that of subbituminous coals and the sulfur in the coal can form SO_3 in the flue gas. This SO_3 is known to make Hg capture using sorbent injection more challenging. However, bituminous coals and waste coals have similar or higher levels of sulfur. The formation of SO_3 is more significant with these coals. Despite all the obstacles and challenges presented to EGUs firing non-lignite coals, all of those EGUs have been subject to the more stringent Hg emission limit of 1.2 lb/TBtu—and emit at or below that emission limit since the rule was fully implemented. Advanced, better performing Hg controls—including ''SO_3 tolerant'' sorbents—are available to allow lignite-fired EGUs to also emit at or below the more stringent Hg emission limit of 1.2 lb/TBtu. As mentioned earlier in this preamble, in 2021, lignite-fired EGUs were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs while generating about 7 percent of total megawatt-hours.

VI. What is the rationale for our other final decisions and amendments from review of the 2020 Technology Review?

A. What did we propose pursuant to CAA section 112(d)(6) for the other NESHAP requirements?

The EPA did not propose any changes to the organic HAP work practice standards, acid gas standards, continental liquid oil-fired EGU standards, non-continental liquid oil-fired EGUs, limited-use oil-fired EGU standards, or standards for IGCC EGUs. The EPA proposed to require that IGCC EGUs use PM CEMS for compliance demonstration with their fPM standard.

The EPA did note in the 2023 Proposal that there have been several recent temporary and localized increases in oil combustion at continental liquid oil-fired EGUs during periods of extreme weather conditions, such as the 2023 polar vortex in New England. As such, the EPA solicited comment on whether the current definition of the limited-use liquid oil-fired subcategory remains appropriate or if, given the increased reliance on oil-fired generation during periods of extreme weather, a period other than the current 24-month period or a different threshold would be more appropriate for the current definition. The EPA also solicited comment on the appropriateness of including new HAP standards for EGUs subject to the limited use liquid oil-fired subcategory, as well as on the means of demonstrating compliance with the new HAP standards.

B. How did the technology review change for the other NESHAP requirements?

The technology review for the organic HAP work practice standards, acid gas standards, and standards for oil-fired EGUs has not changed from the proposal.

The proposed technology review with respect to the use of PM CEMS for compliance demonstration by IGCC EGUs has changed due to comments received on the very low fPM emission rates and on technical challenges with certifying PM CEMS on IGCC EGUs. Therefore, the Agency is not finalizing the required use of PM CEMS for compliance demonstration with the fPM emission standard at IGCC EGUs.

C. What key comments did we receive on the other NESHAP requirements, and what are our responses?

Comment: Commenters urged the EPA to retain the current definition of the limited-use liquid oil-fired subcategory and not to impose new HAP standards on EGUs in this subcategory, given that there are already limits on the amount of fuel oil that can be burned. Commenters noted that the Agency has not identified any justification for the costs required for implementation and compliance with new HAP standards for limited-use liquid oil-fired EGUs. Some commenters alleged that any changes to the existing HAP standards for EGUs in the limited-use liquid oil-fired subcategory may complicate reliability management during cold winter spells or other extreme weather events.

Response: The Agency did not propose changes to the limited-use liquid oil-fired EGU subcategory or to the requirements for such units. To evaluate the potential HAP emission impact of liquid oil-fired EGUs[83] during extreme weather events, the Agency reviewed the 2022 fPM emissions of 11 liquid oil-fired EGUs in the Northeast U.S. that were operated during December 2022 Winter Storm Elliot, as described in the 2024 Technical Memo. The review found that total non-Hg HAP metal emissions during 2022 from the 11 oil-fired EGUs in New England were very small—approximately 70 times lower than the non-Hg HAP metal emissions estimated from oil-fired units

---

[82] For example, the EPA proposed that $27,500 per lb of Hg removed was cost-effective for the Primary Copper RTR (87 FR 1616); and approximately $27,000 per lb of Hg ($2021) was found to be cost-effective in the beyond-the-floor analysis supporting the 2012 MATS Final Rule.

[83] Oil-fired EGUs burning residual fuel oil have generally higher emission rates of HAP compared to that from the use of other types of fuel.

in Puerto Rico, which were among the facilities with the highest (but acceptable) residual risk in the 2020 Residual Risk Review.[84] The EPA will continue to monitor the emissions from the dispatch of limited-use liquid oil-fired EGUs—especially during extreme weather events.

In addition, the Agency reviewed the performance of PM CEMS for compliance demonstration at oil-fired EGUs. Given the higher emission rates and limits from this subcategory of EGUs, the Agency did not find any of the correlation issues with the use of PM CEMS with oil-fired EGUs similar to those that were discussed earlier for coal-fired EGUs. Moreover, the benefits of PM CEMS use that were described earlier (*i.e.,* emissions transparency, operational feedback, *etc.*) translate well to oil-fired EGUs; therefore, the EPA is finalizing the requirement for oil-fired EGUs (excluding limited-use liquid oil-fired EGUs) to use PM CEMS for compliance demonstration, as proposed.

Comment: One commenter recommended that units involved with carbon capture and sequestration (CCS) projects retain the option to use stack testing for compliance demonstration. They said that PM emissions would be measured from the stack downstream of the carbon capture system (they specifically mentioned the carbon capture system being contemplated to be built to capture CO_2 emission from the Milton R. Young Station facility in North Dakota). The commenters said that PM CEMS correlation testing will cause operational impacts on the CCS operations due to operational changes or reduced control efficiencies that temporarily increase PM emissions for long time periods, resulting in CCS operations being adversely affected or even shut down for long periods.

Response: The Agency disagrees with the commenter's recommendation that units utilizing a carbon capture system should be able to continue to use periodic stack testing for compliance demonstration. At the present time, the many ways that CCS can be employed and deployed at coal-fired EGUs supports the use of PM CEMS for compliance purposes. For example, measures (such as a bypass stack) are available that would minimize the operational impacts on the carbon capture system and would allow for proper PM CEMS correlations. Furthermore, the Agency finds that the increased transparency and the improved ability to detect and correct potential control or operational problems offered by PM CEMS, as well as the greater assurance of continuous compliance, outweigh the minor operational impacts potentially experienced. To the extent that a specific coal- or oil-fired EGU utilizing CCS wishes to use an alternative test method for compliance demonstration purposes, its owner or operator may submit a request to the Administrator under the provisions of 40 CFR 63.7(f).

D. What is the rationale for our final approach and decisions regarding the other NESHAP requirements?

The Agency did not receive comments that led to any changes in the outcome of the technology review for other NESHAP requirements as presented in the 2023 Proposal. The Agency did not propose any changes for the current requirements for organic HAP work practice standards, acid gas standards, or standards for oil-fired EGUs and therefore no changes are being finalized.

The EPA is aware of two existing IGCC facilities that meet the definition of an IGCC EGU. The Edwardsport Power Station, located in Knox County, Indiana, includes two IGCC EGUs that had 2021 average capacity factors of approximately 85 percent and 67 percent. These EGUs have LEE qualification for PM, with most current test results of 0.0007 and 0.0003 lb/MMBtu, respectively. The Polk Power Station, located in Polk County, Florida, had a 2021 average capacity factor of approximately 70 percent but burned only natural gas in 2021 (*i.e.,* operating essentially as a natural gas combined cycle turbine EGU). Before this EGU switched to pipeline quality natural gas as a fuel, it qualified for PM LEE status in 2018; to the extent that the EGU again operates as an IGCC, it could continue to claim PM LEE status. While this subcategory has a less stringent fPM standard of 0.040 lb/MMBtu (as compared to that of coal-fired EGUs), recent compliance data indicate fPM emissions well below the most stringent standard option of 0.006 lb/MMBtu that was evaluated for coal-fired EGUs.

The EPA is not finalizing the required use of PM CEMS for compliance demonstration for IGCC EGUs due to technical limitations expressed by commenters. For example, commenters noted that due to differences in stack design, the only possible installation space for a PM CEMS on an IGCC facility is on a stack with elevated grating, exposing the instrument to the elements, which would impact the sensitivity and accuracy of a PM CEMS. Additionally, there are no PM control devices at an IGCC unit available for de-tuning, which is necessary for establishing a correlation curve under PS–11. The EPA has considered these comments and agrees with these noted challenges to the use of PM CEMS at IGCC EGUs and, for those reasons, the EPA is not finalizing the proposed requirement for IGCCs to use PM CEMS for compliance demonstration, thus IGCCs will continue to demonstrate compliance via fPM emissions testing. As a result of comments we received on coal-fired run durations and our consideration on those comments, along with the low levels of reported emissions, the EPA determined that owners or operators of IGCCs will need to ensure each run has a minimum sample volume of 2 dscm or a minimum mass collection of 3 milligrams. In addition, IGCC EGUs will continue to be able to obtain and maintain PM LEE status.

VII. Startup Definition for the Coal- and Oil-Fired EGU Source Category

A. What did we propose for the Coal- and Oil-Fired EGU source category?

In the 2023 Proposal, the EPA proposed to remove the alternative work practice standards, *i.e.,* those contained in paragraph (2) of the definition of "startup" in 40 CFR 63.10042 from the rule based on a petition for reconsideration from environmental groups that was remanded to the EPA in *Chesapeake Climate Action Network* v. *EPA,* 952 F.3d 310 (D.C. Cir. 2020), and responding in part to a separate petition for reconsideration from environmental groups, that sought the EPA's reconsideration of certain aspects of the 2020 Residual Risk Review.[85] The first option under paragraph (1) defines startup as either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose, including onsite use. In the second option, startup is defined as the period in which operation of an EGU is initiated for any purpose, and startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown

---

[84] See *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2019 Risk and Technology Review Proposed Rule* (Docket ID No. EPA–HQ–OAR–2018–0794–0014).

[85] See Document ID No. EPA–HQ–OAR–2018–0794–4565 at *https://www.regulations.gov.*

event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any purpose (including onsite use), or 4 hours after the EGU makes useful thermal energy for industrial, commercial, heating, or cooling purposes, whichever is earlier.

As described in the 2023 Proposal, the Agency proposed to remove paragraph (2) of the definition of ''startup'' as part of our obligation to address the remand on this issue. In addition, as the majority of EGUs currently rely on work practice standards under paragraph (1) of the definition of ''startup,'' we believe this change is achievable by all EGUs and would result in little to no additional expenditures, especially since the additional reporting and recordkeeping requirements associated with use of paragraph (2) would no longer apply. Lastly, the time period for engaging PM or non-Hg HAP metal controls after non-clean fuel use, as well as for full operation of PM or non-Hg HAP metal controls, is expected to be reduced when transitioning to paragraph (1), therefore increasing the duration in which pollution controls are employed and lowering emissions.

B. How did the startup provisions change for the Coal- and Oil-Fired EGU source category?

The EPA is finalizing the amendment to remove paragraph (2) from the definition of ''startup'' as proposed.

C. What key comments did we receive on the startup provisions, and what are our responses?

We received both supportive and adverse comments on the proposed removal of paragraph (2) of the definition of ''startup.'' The summarized comments and the EPA's responses are provided in the *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review Proposed Rule Response to Comments* document. The most significant adverse comments and the EPA's responses are provided below.

Comment: Commenters recommended that the 4-hour startup definition should continue to be allowed as removing it for simplicity is not an adequate justification. They said the EPA is conflating the MACT standard-setting process with this RTR process. Although the EPA notes that the best performing 12 percent of sources do not need this alternative startup definition, commenters stated that this change is beyond the scope of the technology review. Commenters asserted that the EPA's determination that only eight EGUs are currently using that option is insufficient justification for eliminating the definition. Given that the 2023 Proposal did not identify any flaws with the current definition, the commenters stated that the EPA should explain why elimination of the 4-hour definition from MATS is appropriate when there are units currently relying on it. Commenters also stated that the EPA should consider providing reasonable exemptions for the EGUs that currently use that definition, thus gradually phasing out the definition without imposing any additional compliance burdens. The commenters also argued that with potentially lower fPM standards, more facilities may need the additional flexibility allowed by this definition of startup as their margin of compliance is reduced. They noted that startup or non-steady state operation is not conducive to CEMS accuracy and that it may create false reporting of emissions data biased either high or low depending on the actual conditions.

Commenters stated that several facilities are currently required to use the 4-hour startup definition per federal consent decrees or state agreements. They said such a scenario provides clear justification for a limited exemption, as MATS compliance should not result in an EGU violating its consent decree. Commenters noted other scenarios where state permits have special conditions with exemptions from emission limits during ramp-up or ramp-down periods. They said many facilities alleviate high initial emissions by using alternate fuels to begin the combustion process, which has been demonstrated as a Best Management Practice and to lower emissions. Commenters noted that the permit modification process, let alone any physical or operational modifications to the facility, could take significantly longer than the 180-day compliance deadline, depending on public comments, meetings, or contested hearing requests made during the permit process.

Commenters stated the startup definition paragraph (2) has seen limited use due to the additional reporting requirements that the EPA imposed on sources that chose to use the definition, which they believe are unnecessary and should be removed from the rule. The commenters said that the analysis the EPA conducted during the startup/shutdown reconsideration in response to *Chesapeake Climate Action Network* v. *EPA,* 952 F.3d 310 (D.C. Cir. 2020) showed that the definition was reasonable, and they argued that the definition may be needed if the EPA further reduces the limits, given the transitory nature of unit and control operation during these periods. Commenters also stated that the startup definition paragraph (2) is beneficial to units that require extended startups. They said including allowances for cold startup conditions could allow some EGUs to continue operation until more compliant generation is built, which would help facilitate a smooth transition to newer plants that meet the requirements without risking the reliability of the electric grid. Commenters also noted that some control devices, such as ESPs, may not be operating fully even when the plant begins producing electricity.

Commenters stated that the EPA should consider allowing the use of diluent cap values from 40 CFR part 75. As these are limited under MATS, commenters noted that startup and shutdown variations are more pronounced than if diluent caps were to be allowed. They said that with a lower emissions limitation, the diluent cap would mathematically correct for calculation inaccuracies inherent in emission rate calculation immediately following startup. Commenters stated that relative accuracy test audits (RATA) must be conducted at greater than 50 percent load under 40 CFR part 60 and at normal operating load under 40 CFR part 75. They said that it is not reasonable to require facilities to certify their CEMS, including PM CEMS, at greater than 50 percent capacity and use it for compliance at less than 50 percent capacity. Commenters stated that startups have constantly changing flow and temperatures that do not allow compliance tests to be conducted during these periods.

Response: The Agency disagrees with the commenters who suggest that the 4-hour startup duration should be retained. As mentioned in the 2023 Proposal (88 FR 24885), owners or operators of coal- and oil-fired EGUs that generated over 98 percent of electricity in 2022 have made the requisite adjustments, whether through greater clean fuel capacity, better tuned equipment, better trained staff, a more efficient and/or better design structure, or a combination of factors, to be able to meet the requirements of paragraph (1) of the startup definition. This ability points out an improvement in operation that all EGUs should be able to meet at little to no additional expenditure, since the additional recordkeeping and reporting provisions associated with the work practice standards of paragraph (2) of the startup definition were more expensive than the requirements of paragraph (1) of the definition. As mentioned with respect to gathering experience with PM CEMS, the Agency believes owners or operators of the 8 EGUs relying on the 4-hour startup period can build on their startup experience gained since finalization of the 2012 MATS Final Rule, along with the experience shared by some of the other EGUs that have been able to conform with startup definition paragraph (1), as well as the experience to be obtained in the period yet remaining before compliance is required; such experience could prove key to aiding source owners or operators in their shift from reliance on startup definition paragraph (2) to startup definition paragraph (1). Should EGU owners or operators find that their attempts to rely on startup definition (1) are unsuccessful after application of that experience, they may request of the Administrator the ability to use an alternate non-opacity standard, as described in the NESHAP general provisions at 40 CFR 63.6(g). Before the Administrator's approval can be granted, the EGU owner or operator's request must appear in the **Federal Register** for the opportunity for notice and comment by the public, as required in 40 CFR 63.6(g)(1).

Regarding consent decrees or state agreements for requirements other than those contained in this rule, while the rule lacks the ability to revise such agreements, the EPA recommends that EGU owners or operators contact the other parties to see what, if any, revisions could be made. Nonetheless, the Agency expects EGU source owners or operators to comply with the revised startup definition by the date specified in this rule. Given the concern expressed by the commenters for some sources, the Agency expects such source owners or operators to begin negotiations with other parties for other non-rule obligations to begin early enough to be completed prior to the compliance date specified in this rule.

The Agency disagrees with the commenters' suggestions that startup definition paragraph (2)'s reporting requirements were too strict to be used. That suggestion is not consistent with the number of commenters who claimed to need to use paragraph (2) of the startup definition, even though only 2.5 percent of EGUs currently rely on this startup definition. The Agency's experience is that almost all EGU source owners or operators have been able to adjust their unit operation such that adherence to startup definition paragraph (1) reduced, if not eliminated, the concern by some about use of startup definition paragraph (1). As mentioned earlier in this document, the better performers in the coal-fired EGU source category no longer need to have, or use, paragraph (2) of the startup definition after gaining experience with using paragraph (1).

The Agency disagrees with the commenter's suggestion that the diluent cap values allowed for use by 40 CFR part 75 be included in the rule, because diluent cap values are already allowed for use during startup and shutdown periods per 40 CFR 63.10007(f)(1). Note that while emission values are to be recorded and reported during startup and shutdown periods, they are not to be used in compliance calculations per 40 CFR 63.10020(e). In addition to diluent cap use during startup and shutdown periods, section 6.2.2.3 of appendix C to 40 CFR part 63, subpart UUUUU allows diluent cap use for PM CEMS during any periods when oxygen or CO_2 values exceed or dip below, respectively, the cap levels. Diluent cap use for other periods from other regulations are not necessary for MATS. The Agency does not understand the commenter's suggestion concerning the load requirement for a RATA. The Agency believes the commenter may have mistaken HCl CEMS requirements, which use RATAs but were not proposed to be changed, with PM CEMS requirements, which do not use RATAs. Since PM CEMS are not subject to RATAs and the Agency did not propose changes to requirements for HCl CEMS, the comment on RATAs being conducted at greater than 50 percent load is moot. The EPA is finalizing the removal of startup definition paragraph (2), as proposed.

D. What is the rationale for our final approach and final decisions for the startup provisions?

The EPA is finalizing the removal of paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042 consistent with reasons described in the 2023 Proposal. As the majority of EGUs are already relying on the work practice standards in paragraph (1) of the startup definition, the EPA finds that such a change is achievable within the 180-day compliance timeline by all EGUs at little to no additional expenditure since the additional reporting and recordkeeping provisions under paragraph (2) were more expensive than paragraph (1). Additionally, the time period for engaging pollution controls for PM or non-Hg HAP metals is expected to be reduced when transitioning to paragraph (1), therefore increasing the duration in which pollution controls are employed and lowering emissions.

VIII. What other key comments did we receive on the proposal?

Comment: Some commenters argued that it is well-established that cost is a major consideration in rulemakings reviewing existing NESHAP under CAA section 112(d)(6). In particular, commenters cited to *Michigan* v. *EPA,* 576 U.S. 743, 759 (2015), to support the argument that the EPA must consider the costs of the regulation in relation to the benefits intended by the statutory requirement mandating this regulation, that is, the benefits of the HAP reductions. Commenters stated that the EPA should not seek to impose the excessive costs associated with this action as there would be no benefit associated with reducing HAP. The commenters said that the EPA certainly should not do so for an industry that is rapidly reducing its emissions because it is on the way to retiring most, if not all, units in the source category in little over a decade. The commenters also claimed that as *Michigan* held that cost and benefits must be considered in determining whether it is ''appropriate'' to regulate EGUs under CAA section 112 in the first place, it necessarily follows that the same threshold must also apply when the EPA subsequently reviews the standards.

Response: The EPA agrees that it is appropriate to take costs into consideration in deciding whether it is necessary to revise an existing NESHAP under CAA section 112(d)(6). As explained in the 2023 Proposal and this document, the EPA has carefully considered the costs of compliance and the effects of those costs on the industry. Although the commenters seem to suggest that the EPA should weigh the costs and benefits of the revisions to the standard, we do not interpret the comments as arguing that the EPA should undertake a formal benefit cost analysis but rather the commenters believe that the EPA should instead limit its analysis supporting the standard to HAP emission reductions. Our consideration of costs in this rulemaking is consistent with the Supreme Court's direction in *Michigan* where the Court noted that ''[i]t will be up to the Agency to decide (as always, within the limits of reasonable interpretation) how to account for cost,'' 576 U.S. 743, 759 (2015), and with comments arguing that the EPA should focus its decision-making on the standard on the anticipated reductions in HAP.

In *Michigan,* the Supreme Court concluded that the EPA erred when it concluded it could not consider costs when deciding as a threshold matter whether it is ''appropriate and necessary'' under CAA section 112(n)(1)(A) to regulate HAP from EGUs, despite the relevant statutory provision containing no specific reference to cost. 576 U.S. at 751. In doing so, the Court held that the EPA ''must consider cost—including, most importantly, cost of compliance—before deciding whether regulation is appropriate and necessary'' under CAA section 112. *Id.* at 759. In examining the language of CAA section 112(n)(1)(A), the Court concluded that the phrase ''appropriate and necessary'' was ''capacious'' and held that ''[r]ead naturally in the present context, the phrase 'appropriate and necessary' requires at least some attention to cost.'' *Id.* at 752. As is clear from the record for this rulemaking, the EPA has carefully considered cost in reaching its decision to revise the NESHAP in this action.

The EPA has also taken into account the numerous HAP-related benefits of the final rule in deciding to take this action. These benefits include not only the reduced exposure to Hg and non-Hg HAP metals, but also the additional transparency provided by PM CEMS for communities that live near sources of HAP, and the assurance PM CEMS will provide that the standards are being met on a continuous basis. As discussed in section II.B.2., and section IX.E. many of these important benefits are not able to be monetized. Although this rule will result in the reduction of HAP, including Hg, lead, arsenic, chromium, nickel, and cadmium, data limitations prevent the EPA from assigning monetary value to those reductions. In addition, there are several benefits associated with the use of PM CEMS which are not quantified in this rule.

While the Court's examination of CAA section 112(n)(a)(1) in *Michigan* considered a different statutory provision than CAA section 112(d)(6) under which the EPA is promulgating this rulemaking, the EPA has nonetheless satisfied the Court's directive to consider costs, both in the context of the individual revisions to MATS (as directed by the language of the statute) and in the context of the rulemaking as a whole. Moreover, while the EPA is not required to undertake a ''formal cost benefit analysis in which each advantage and disadvantage [of a regulation] is assigned a monetary value,'' *Michigan,* 576 U.S. at 759, the EPA has contemplated and carefully considered both the advantages and disadvantages of the revisions it is finalizing here, including qualitative and quantitative benefits of the regulation and the costs of compliance.

IX. Summary of Cost, Environmental, and Economic Impacts and Additional Analyses Conducted

The following analyses of costs and benefits, and environmental, economic, and environmental justice impacts are presented for the purpose of providing the public with an understanding of the potential consequences of this final action. The EPA notes that analysis of such impacts is distinct from the determinations finalized in this action under CAA section 112, which are based on the statutory factors the EPA discussed in section II.A. and sections IV. through VII.

The EPA's obligation to conduct an analysis of the potential costs and benefits under Executive Order 12866, discussed in this section and section X.A., is distinct from its obligation in setting standards under CAA section 112 to take costs into account. As explained above, the EPA considered costs in multiple ways in choosing appropriate standards consistent with the requirements of CAA section 112. The benefit-cost analysis is performed to comply with Executive Order 12866. The EPA, however, did not rely on that analysis in choosing the appropriate standard here, consistent with the Agency's longstanding interpretation of the statute. As discussed at length in section II.B.2. above and in the EPA's 2023 final rulemaking finalizing the appropriate and necessary finding (88 FR 13956), historically there have been significant challenges in monetizing the benefits of HAP reduction. Important categories of benefits from reducing HAP cannot be monetized, making benefit-cost analysis ill-suited to the EPA's decision making on regulating HAP emissions under CAA section 112. Further, there are also unquantified emission reductions anticipated from installing PM CEMS, as discussed in section IX.E. For this reason, combined with Congress's recognition of the particular dangers posed by HAP and consequent direction to the EPA to reduce emissions of these pollutants to the ''maximum degree,'' the EPA does not at this time believe it is appropriate to rely on the results of the monetized benefit-cost analysis when setting the standards.

As noted in section X.A. below, the EPA projects that the net monetized benefits of this rule are negative. Many of the benefits of this rule discussed at length in this section and elsewhere in this record, however, were not monetized. This rule will result in the reduction of HAP, including Hg, lead, arsenic, chromium, nickel, and cadmium,[86] consistent with Congress's direction in CAA section 112 discussed in section II.A. of this final rule. At this time, data limitations prevent the EPA from assigning monetary value to those reductions, as discussed in section II.B.2. above.[87] In addition, the benefits of the additional transparency provided by the requirement to use PM CEMS for communities that live near sources of HAP, and the assurance PM CEMS provide that the standards are being met on a continuous basis were not monetized due to data limitations. While the EPA does not believe benefit-cost analysis is the right way to determine the appropriateness of a standard under CAA section 112, the EPA notes that when all of the costs and benefits are considered (including non-monetized benefits), this final rule is a worthwhile exercise of the EPA's CAA section 112(d)(6) authority.

A. What are the affected facilities?

The EPA estimates that there are 314 coal-fired EGUs [88] and 58 oil-fired EGUs that will be subject to this final rule by the compliance date.

B. What are the air quality impacts?

The EPA estimated emission reductions under the final rule for the years 2028, 2030, and 2035 based upon IPM projections. The quantified emissions estimates were developed with the EPA's Power Sector Modeling Platform 2023 using IPM, a state-of-the-art, peer-reviewed dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. IPM provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies while meeting electricity demand and various environmental, transmission, dispatch, and reliability constraints. IPM's least-cost dispatch

---

[86] As of 2023, three of the HAP metals or their compounds emitted by EGUs (arsenic, chromium, and nickel) are classified as carcinogenic to humans. More details are available in section II.B.2. and Chapter 4.2.2 of the RIA.

[87] *See also National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration and Affirmation of the Appropriate and Necessary Supplemental Finding,* 88 FR 13956, 13970–73 (March 6, 2023) (for additional discussion regarding the limitations to monetizing and quantifying most benefits from HAP reductions in the 2023 rulemaking finalizing the appropriate and necessary finding).

[88] The number of coal-fired affected EGUs is larger than the 296 coal-fired EGUs assessed for the fPM standard in section IV. because it includes four EGUs that burn petroleum coke (which are a separate subcategory for MATS) and 14 EGUs without fPM compliance data available on the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), *https://www.epa.gov/electronic-reporting-air-emissions/cedri.*

solution is designed to ensure generation resource adequacy, either by using existing resources or through the construction of new resources. IPM addresses reliable delivery of generation resources for the delivery of electricity between the 78 IPM regions, based on current and planned transmission capacity, by setting limits to the ability to transfer power between regions using the bulk power transmission system. The model includes state-of-the-art estimates of the cost and performance of air pollution control technologies with respect to Hg and other HAP controls.

The quantified emission reduction estimates presented in the RIA include reductions in pollutants directly covered by this rule, such as Hg, and changes in other pollutants emitted from the power sector as a result of the compliance actions projected under this final rule. Table 8 of this document presents the projected emissions under the final rule. Note that, unlike the cost-effectiveness analysis presented in sections IV. and V. of this preamble, the projections presented in table 8 are incremental to a projected baseline which reflects future changes in the composition of the operational coal-fired EGU fleet that are projected to occur by 2035 as a result of factors affecting the power sector, such as the IRA, promulgated regulatory actions, or changes in economic conditions.

BILLING CODE 6560–50–P

Table 8. Projected EGU Emissions in the Baseline and Under the Final Rule: 2028, 2030, and 2035[a]

		Total Emissions			
	Year	Baseline	Final Rule	Change from Baseline	% Change
Hg (lb)	2028	6,129	5,129	-999	-16%
	2030	5,863	4,850	-1,013	-17%
	2035	4,962	4,055	-907	-18%
$PM_{2.5}$ (thousand tons)	2028	70.5	69.7	-0.8	-1.1%
	2030	66.3	65.8	-0.5	-0.8%
	2035	50.7	50.2	-0.5	-0.9%
PM_{10} (thousand tons)	2028	79.5	77.4	-2.1	-2.6%
	2030	74.5	73.1	-1.3	-1.8%
	2035	56.0	54.8	-1.2	-2.1%
SO_2 (thousand tons)	2028	454.3	454.0	-0.3	-0.1%
	2030	333.5	333.5	0.0	0.0%
	2035	239.9	239.9	0.0	0.0%
Ozone-season NO_x (thousand tons)	2028	189.0	188.8	-0.165	-0.09%
	2030	174.9	175.4	0.488	0.28%
	2035	116.9	119.1	2.282	1.95%
Annual NO_x (thousand tons)	2028	460.5	460.3	-0.283	-0.06%
	2030	392.8	392.7	-0.022	-0.01%
	2035	253.4	253.5	0.066	0.03%
HCl (thousand tons)	2028	2.5	2.5	0.0	0.0%
	2030	2.2	2.2	0.0	0.0%
	2035	1.5	1.5	0.0	0.1%
CO_2 (million metric tons)	2028	1,158.8	1,158.7	-0.1	0.0%
	2030	1,098.3	1,098.3	0.0	0.0%
	2035	724.2	724.1	-0.1	0.0%

[a] This analysis is limited to the geographically contiguous lower 48 states.

BILLING CODE 6560–50–C

In addition to the projected emissions impacts presented in table 8, we also estimate that the final rule will reduce at least 7 tons of non-Hg HAP metals in 2028, 5 tons of non-Hg HAP metals in 2030, and 4 tons of non-Hg HAP metals in 2035. These reductions are composed of reductions in emissions of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.[89]

Importantly, the continuous monitoring of fPM required in this rule will likely induce additional emissions reductions that we are unable to quantify. Continuous measurements of emissions accounts for changes to processes and fuels, fluctuations in load, operations of pollution controls, and equipment malfunctions. By measuring emissions across all operations, power plant operators and regulators can use the data to ensure controls are operating properly and to assess compliance with relevant standards. Because CEMS enable power plant operators to quickly identify and correct problems with pollution control devices, it is possible that fPM emissions could be lower than they otherwise would have been for up to 3 months—or up to 3 years if testing less frequently under the LEE program—at a time. This potential reduction in fPM and non-Hg HAP metals emission resulting from the information provided by continuous monitoring coupled with corrective actions by plant operators could be sizeable over the existing coal-fired fleet and is not quantified in this rulemaking.

Section 3 of the RIA presents a detailed discussion of the emissions projections under the regulatory options as described in the RIA. Section 3 also describes the compliance actions that are projected to produce the emission reductions in table 8 of this preamble. Please see section IX.E. of this preamble and section 4 of the RIA for detailed discussions of the projected health, welfare, and climate benefits of these emission reductions.

C. What are the cost impacts?

The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and policy scenarios. In other words, these costs are an estimate of the increased power industry expenditures required to implement the final requirements of this rule. The compliance cost estimates were mainly developed using the EPA's Power Sector Modeling Platform 2023 using IPM. The incremental costs of the final rule's PM CEMS requirement were estimated outside of IPM and added to the IPM-based cost estimate presented here and in section 3 of the RIA.

We estimate the present value (PV) of the projected compliance costs over the 2028 to 2037 period, as well as estimate the equivalent annual value (EAV) of the flow of the compliance costs over this period. All dollars are in 2019 dollars. We estimate the PV and EAV using 2, 3, and 7 percent discount rates.[90] Table 9 of this document presents the estimates of compliance costs for the final rule.

Table 9. Projected Compliance Costs of the Final Rule, 2028 through 2037 (Millions 2019$, Discounted to 2023)[a]

	2% Discount Rate	3% Discount Rate	7% Discount Rate
PV	860	790	560
EAV	96	92	80

[a] Values have been rounded to two significant figures.

The PV of the compliance costs for the final rule, discounted at the 2 percent rate, is estimated to be about $860 million, with an EAV of about $96 million. At the 3 percent discount rate, the PV of the compliance costs of the final rule is estimated to be about $790 million, with an EAV of about $92 million. At the 7 percent discount rate, the PV of the compliance costs of the rule is estimated to be about $560 million, with an EAV of about $80 million.

We note that IPM provides the EPA's best estimate of the costs of the rules to the electricity sector and related energy sectors (*i.e.,* natural gas, coal mining). These compliance cost estimates are used as a proxy for the social cost of the rule. For a detailed description of these compliance cost projections, please see section 3 of the RIA, which is available in the docket for this action.

D. What are the economic impacts?

The Agency estimates that this rule will require additional fPM and/or Hg removal at less than 15 GW of operable capacity in 2028, which is about 14 percent of the total coal-fired EGU capacity projected to operate in that year. The units requiring additional fPM and/or Hg removal are projected to generate less than 2 percent of total generation in 2028. Moreover, the EPA does not project that any EGUs will retire in response to the standards promulgated in this final rule.

Consistent with the small share of EGUs required to reduce fPM and/or Hg emissions rates, this final action has limited energy market implications. There are limited impacts on energy prices projected to result from this final rule. On a national average basis,

---

[89] Note that modeled projections include total PM_{10} and total $PM_{2.5}$. The EPA estimated non-Hg HAP metals reductions by multiplying the ratio of non-Hg HAP metals to fPM by modeled projections of total PM_{10} reductions under the rule. The ratios of non-Hg HAP metals to fPM were based on analysis of 2010 MATS Information Collection Request (ICR) data. As there may be substantially more fPM than PM_{10} reduced by the control techniques projected to be used under this rule, these estimates of non-Hg HAP metals reductions are likely underestimates. More detail on the estimated reduction in non-Hg HAP metals can be found in the docketed memorandum *Estimating Non-Hg HAP Metals Reductions for the 2024 Technology Review for the Coal-Fired EGU Source Category.*

[90] Results using the 2 percent discount rate were not included in the proposal for this action. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default rates to discount social costs and benefits. The analysis of the proposed rule used these two recommended rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent rate to discount social costs and benefits (subject to regular updates). The Circular A–4 update also recommended consideration of the shadow price of capital when costs or benefits are likely to accrue to capital. As a result of the update to Circular A–4, we include cost and benefits results calculated using a 2 percent discount rate.

delivered coal, natural gas, and retail electricity prices are not projected to change. The EPA does not project incremental changes in existing operational capacity to occur in response to the final rule. Coal production for use in the power sector is not projected to change significantly by 2028.

The short-term estimates for employment needed to design, construct, and install the control equipment in the 3-year period before the compliance date are also provided using an approach that estimates employment impacts for the environmental protection sector based on projected changes from IPM on the number and scale of pollution controls and labor intensities in relevant sectors. Finally, some of the other types of employment impacts that will be ongoing are estimated using IPM outputs and labor intensities, as reported in section 5 of the RIA.

E. What are the benefits?

The RIA for this action analyzes the benefits associated with the projected emission reductions under this rule. This final rule is projected to reduce emissions of Hg and non-Hg HAP metals, as well as $PM_{2.5}$, SO_2, NO_X and CO_2 nationwide. The potential impacts of these emission reductions are discussed in detail in section 4 of the RIA. The EPA notes that the benefits analysis is distinct from the statutory determinations finalized herein, which are based on the statutory factors the EPA is required to consider under CAA section 112. The assessment of benefits described here and in the RIA is presented solely for the purposes of complying with Executive Order 12866, as amended by Executive Order 14094, and providing the public with a complete depiction of the impacts of the rulemaking.

Hg is a persistent, bioaccumulative toxic metal emitted from power plants that exists in three forms: gaseous elemental Hg, inorganic Hg compounds, and organic Hg compounds (*e.g.,* methylmercury). Hg can also be emitted in a particle-bound form. Elemental Hg can exist as a shiny silver liquid, but readily vaporizes into air. Airborne elemental Hg does not quickly deposit or chemically react in the atmosphere, resulting in residence times that are long enough to contribute to global scale deposition. Oxidized Hg and particle-bound Hg deposit quickly from the atmosphere impacting local and regional areas in proximity to sources. Methylmercury is formed by microbial action in the top layers of sediment and soils, after Hg has precipitated from the air and deposited into waterbodies or land. Once formed, methylmercury is taken up by aquatic organisms and bioaccumulates up the aquatic food web. Larger predatory fish may have methylmercury concentrations many times that of the concentrations in the freshwater body in which they live.

All forms of Hg are toxic, and each form exhibits different health effects. Acute (short-term) exposure to high levels of elemental Hg vapors results in central nervous system (CNS) effects such as tremors, mood changes, and slowed sensory and motor nerve function. Chronic (long-term) exposure to elemental Hg in humans also affects the CNS, with effects such as erethism (increased excitability), irritability, excessive shyness, and tremors. The major effect from chronic ingestion or inhalation of low levels of inorganic Hg is kidney damage.

Methylmercury is the most common organic Hg compound in the environment. Acute exposure of humans to very high levels of methylmercury results in profound CNS effects such as blindness and spastic quadriparesis. Chronic exposure to methylmercury, most commonly by consumption of fish from Hg contaminated waters, also affects the CNS with symptoms such as paresthesia (a sensation of pricking on the skin), blurred vision, malaise, speech difficulties, and constriction of the visual field. Ingestion of methylmercury can lead to significant developmental effects, such as IQ loss measured by performance on neurobehavioral tests, particularly on tests of attention, fine motor-function, language, and visual spatial ability. In addition, evidence in humans and animals suggests that methylmercury can have adverse effects on both the developing and the adult cardiovascular system, including fatal and non-fatal ischemic heart disease (IHD). Further, nephrotoxicity, immunotoxicity, reproductive effects (impaired fertility), and developmental effects have been observed with methylmercury exposure in animal studies.[91] Methylmercury has some genotoxic activity and can cause chromosomal damage in several experimental systems. The EPA has concluded that mercuric chloride and methylmercury are possibly carcinogenic to humans.[92] [93]

The projected emissions reductions of Hg are expected to lower deposition of Hg into ecosystems and reduce U.S. EGU attributable bioaccumulation of methylmercury in wildlife, particularly for areas closer to the effected units subject to near-field deposition. Subsistence fishing is associated with vulnerable populations. Methylmercury exposure to subsistence fishers from lignite-fired units is below the current RfD for methylmercury neurodevelopmental toxicity. The EPA considers exposures at or below the RfD for methylmercury unlikely to be associated with appreciable risk of deleterious effects across the population. However, the RfD for methylmercury does not represent an exposure level corresponding to zero risk; moreover, the RfD does not represent a bright line above which individuals are at risk of adverse effects. Reductions in Hg emissions from lignite-fired facilities should further reduce exposure to methylmercury for subsistence fisher sub-populations located in the vicinity of these facilities, which are all located in North Dakota, Texas, and Mississippi.

In addition, U.S. EGUs are a major source of HAP metals emissions including selenium, arsenic, chromium, nickel, and cobalt, cadmium, beryllium, lead, and manganese. Some HAP metals emitted by U.S. EGUs are known to be persistent and bioaccumulative and others have the potential to cause cancer. Exposure to these HAP metals, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. The emissions reductions projected under this final rule are expected to reduce human exposure to non-Hg HAP metals, including carcinogens.

Furthermore, there is the potential for reductions in Hg and non-Hg HAP metal emissions to enhance ecosystem services and improve ecological outcomes. The reductions will potentially lead to positive economic impacts although it is difficult to estimate these benefits and, consequently, they have not been included in the set of quantified benefits.

As explained in section IX.B., the continuous monitoring of fPM required in this rule may induce further reductions of fPM and non-Hg HAP metals than we project in the RIA for

---

[91] Agency for Toxic Substances and Disease Registry (ATSDR). Toxicological Profile for Mercury. Public Health Service, U.S. Department of Health and Human Services, Atlanta, GA. 2022.

[92] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Methylmercury. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 2001.

[93] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Mercuric Chloride. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1995.

this action. As a result, there may be additional unquantified beneficial health impacts from these potential reductions. The continuous monitoring of fPM required in this rule is also likely to provide several additional benefits to the public which are not quantified in this rule, including greater certainty, accuracy, transparency, and granularity in fPM emissions information than exists today.

The rule is also expected to reduce emissions of direct $PM_{2.5}$, NO_X, and SO_2 nationally throughout the year. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects. The rule is also expected to reduce ozone-season NO_X emissions nationally in most years of analysis. In the presence of sunlight, NO_X, and volatile organic compounds (VOCs) can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X emissions in most locations reduces human exposure to ozone and reduces the incidence of ozone-related health effects, although the degree to which ozone is reduced will depend in part on local concentration levels of VOCs.

The health effect endpoints, effect estimates, benefit unit values, and how they were selected, are described in the technical support document titled *Estimating $PM_{2.5}$* $^{\text{minus;}}$ *and Ozone-Attributable Health Benefits* (2023). This document describes our peer-reviewed approach for selecting and quantifying adverse effects attributable to air pollution, the demographic and health data used to perform these calculations, and our methodology for valuing these effects.

Because of projected changes in dispatch under the final requirements, the rule is also projected to impact CO_2 emissions. The EPA estimates the climate benefits of CO_2 emission reductions expected from the final rule using estimates of the social cost of carbon (SC–CO_2) that reflect recent advances in the scientific literature on climate change and its economic impacts and that incorporate recommendations made by the National Academies of Science, Engineering, and Medicine.[94] The EPA published and used these estimates in the RIA for the December 2023 Natural Gas Sector final rule titled *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* (2023 Oil and Natural Gas NSPS/EG).[95] The EPA solicited public comment on the methodology and use of these estimates in the RIA for the Agency's December 2022 Oil and Natural Gas Sector supplemental proposal [96] that preceded the 2023 Oil and Natural Gas NSPS/EG and has conducted an external peer review of these estimates. The response to public comments document and the response to peer reviewer recommendations can be found in the docket for the 2023 Oil and Natural Gas NSPS/EG action. Complete information about the peer review process is also available on the EPA's website.[97]

Section 4.4 within the RIA for this final rulemaking provides an overview of the methodological updates incorporated into the SC–CO_2 estimates used in this final RIA.[98] A more detailed explanation of each input and the modeling process is provided in the final technical report, *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances.*[99]

The SC–CO_2 is the monetary value of the net harm to society associated with a marginal increase in CO_2 emissions in a given year, or the benefit of avoiding that increase. In principle, SC–CO_2 includes the value of all climate change impacts both negative and positive, including, but not limited to, changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC–CO_2, therefore, reflects the societal value of reducing emissions of CO_2 by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CO_2 emissions. In practice, data and modeling limitations restrain the ability of SC–CO_2 estimates to include all physical, ecological, and economic impacts of climate change, implicitly assigning a value of zero to the omitted climate damages. The estimates are, therefore, a partial accounting of climate change impacts and likely underestimate the marginal benefits of abatement.

Table 10 of this document presents the estimated PV and EAV of the projected health and climate benefits across the regulatory options examined in the RIA in 2019 dollars discounted to 2023.

BILLING CODE 6560–50–P

---

[94] National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. National Academies Press.

[95] *Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* Docket ID No. EPA–HQ–OAR–2021–0317, December 2023.

[96] *Supplemental Notice of Proposed Rulemaking for Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* 87 FR 74702 (December 6, 2022).

[97] *https://www.epa.gov/environmental-economics/scghg-tsd-peer-review.*

[98] Note that the RIA for the proposal of this rulemaking used the SC–CO_2 estimates from the Interagency Working Group's (IWG) February 2021 Social Cost of Greenhouse Gases Technical Support Document (TSD) (IWG 2021) to estimate climate benefits. These SC–CO_2 estimates were interim values recommended for use in benefit-cost analyses until updated estimates of the impacts of climate change could be developed. Estimated climate benefits using these interim SC–CO_2 values (IWG 2021) are presented in Appendix B of the RIA for this final rulemaking for comparison purposes.

[99] Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,'' *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances,* Docket ID No. EPA–HQ–OAR–2021–0317, November 2023.

Table 10. Projected Benefits of the Final Rule, 2028 through 2037 (Millions 2019$, Discounted to 2023)[a]

Present Value (PV)			
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	300	260	180
Climate Benefits[d]	130	130	130
Total Monetized Benefits[e]	420	390	300
Equivalent Annual Value (EAV)[b]			
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	33	31	25
Climate Benefits[d]	14	14	14
Total Monetized Benefits [e]	47	45	39
Non-Monetized Benefits	Benefits from reductions of about 900 to 1000 pounds of Hg annually		
	Benefits from reductions of at least 4 to 7 tons of non-Hg HAP metals annually		
	Benefits from improved water quality and availability		
	Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS		

[a] Values have been rounded to two significant figures. Rows may not appear to sum correctly due to rounding.

[b] The EAV of benefits are calculated over the 10-year period from 2028 to 2037.

[c] The projected monetized air quality-related benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3, and 7 percent.

[d] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of carbon dioxide (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see section 4 of the RIA for the full range of monetized climate benefit estimates.

[e] The list of non-monetized benefits does not include all potential non-monetized benefits. See table 4-8 of the RIA for a more complete list.

BILLING CODE 6560–50–C

This final rule is projected to reduce $PM_{2.5}$ and ozone concentrations, producing a projected PV of monetized health benefits of about $300 million, with an EAV of about $33 million discounted at 2 percent. The projected PV of monetized climate benefits of the final rule is estimated to be about $130 million, with an EAV of about $14 million using the SC–$CO_2$ discounted at 2 percent.[100] Thus, this final rule would

---

[100] Monetized climate benefits are discounted using a 2 percent discount rate, consistent with the EPA's updated estimates of the SC–CO_2. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital (OMB 2023). Because the SC–CO_2 estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under

generate a PV of monetized benefits of $420 million, with an EAV of $47 million discounted at a 2 percent rate.

At a 3 percent discount rate, this final rule is expected to generate projected PV of monetized health benefits of $260 million, with an EAV of about $31 million discounted at 3 percent. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $130 million, with an EAV of about $14 million using the SC–$CO_2$. Thus, this final rule would generate a PV of monetized benefits of $390 million, with an EAV of $45 million discounted at a 3 percent rate.

At a 7 percent discount rate, this final rule is expected to generate projected PV of monetized health benefits of $180 million, with an EAV of about $25 million discounted at 7 percent. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $130 million, with an EAV of about $14 million using the SC–$CO_2$. Thus, this final rule would generate a PV of monetized benefits of $300 million, with an EAV of $39 million discounted at a 7 percent rate.

The benefits from reducing Hg and non-Hg HAP metals and from unquantified improvements in water quality were not monetized and are therefore not directly reflected in the monetized benefit-cost estimates associated with this rulemaking. Potential benefits from the increased transparency and accelerated identification of anomalous emission anticipated from requiring PM CEMS were also not monetized in this analysis and are therefore also not directly reflected in the monetized benefit-cost comparisons. We nonetheless consider these impacts in our evaluation of the net benefits of the rule and find that, if we were able to monetize these beneficial impacts, the final rule would have greater net benefits than shown in table 11 of this document.

F. What analysis of environmental justice did we conduct?

For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 ‘‘Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,’’ which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action may involve potential EJ concerns if it could: (1) create new disproportionate impacts on communities with EJ concerns; (2) exacerbate existing disproportionate impacts on communities with EJ concerns; or (3) present opportunities to address existing disproportionate impacts on communities with EJ concerns through this action under development.

The EPA's EJ technical guidance states that ‘‘[t]he analysis of potential EJ concerns for regulatory actions should address three questions: (A) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline? (B) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration? (C) For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?'' [101]

The environmental justice analysis is presented for the purpose of providing the public with as full as possible an understanding of the potential impacts of this final action. The EPA notes that analysis of such impacts is distinct from the determinations finalized in this action under CAA section 112, which are based solely on the statutory factors the EPA is required to consider under that section. To address these questions in the EPA's first quantitative EJ analysis in the context of a MATS rule, the EPA developed a unique analytical approach that considers the purpose and specifics of this rulemaking, as well as the nature of known and potential disproportionate and adverse exposures and impacts. However, due to data limitations, it is possible that our analysis failed to identify disparities that may exist, such as potential EJ characteristics (*e.g.,* residence of historically red-lined areas), environmental impacts (*e.g.,* other ozone metrics), and more granular spatial resolutions (*e.g.,* neighborhood scale) that were not evaluated. Also due to data and resource limitations, we discuss HAP and climate EJ impacts of this action qualitatively (section 6 of the RIA).

For this rule, we employ two types of analysis to respond to the previous three questions: proximity analyses and exposure analyses. Both types of analysis can inform whether there are potential EJ concerns in the baseline (question 1).[102] In contrast, only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns after implementation of the regulatory options under consideration (question 2) and whether potential EJ concerns will be created or mitigated compared to the baseline (question 3). While the exposure analysis can respond to all three questions, several caveats should be noted. For example, the air pollutant exposure metrics are limited to those used in the benefits assessment. For ozone, that is the maximum daily 8-hour average, averaged across the April through September warm season (AS–MO3) and for $PM_{2.5}$ that is the annual average. This ozone metric likely smooths potential daily ozone gradients and is not directly relatable to the National Ambient Air Quality Standards (NAAQS), whereas the $PM_{2.5}$ metric is more similar to the long-term $PM_{2.5}$ standard. The air quality modeling estimates are also based on state and fuel level emission data paired with facility-level baseline emissions and provided at a resolution of 12 square kilometers. Additionally, here we focus on air quality changes due to this rulemaking and infer post-policy ozone and $PM_{2.5}$ exposure burden impacts. Note, we discuss HAP and climate EJ impacts of this action qualitatively (section 6 of the RIA).

Exposure analysis results are provided in two formats: aggregated and distributional. The aggregated results provide an overview of potential ozone exposure differences across populations at the national- and state-levels, while the distributional results show detailed information about ozone concentration changes experienced by everyone within each population.

In section 6 of the RIA, we utilize the two types of analysis to address the three EJ questions by quantitatively evaluating: (1) the proximity of affected facilities to various local populations with potential EJ concerns (section 6.4); and (2) the potential for disproportionate ozone and $PM_{2.5}$ concentrations in the baseline and concentration changes after rule implementation across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, life expectancy, redlining, Tribal land, age, sex, educational attainment,

---

OMB Circular A–4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC–CO_2. See Section 4.4 of the RIA for more discussion.

[101] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

[102] The baseline for proximity analyses is current population information, whereas the baseline for ozone exposure analyses are the future years in which the regulatory options will be implemented (*e.g.,* 2023 and 2026).

and degree of linguistic isolation (section 6.5). It is important to note that due to the small magnitude of underlying emissions changes, and the corresponding small magnitude of the ozone and $PM_{2.5}$ concentration changes, the rule is expected to have only a small impact on the distribution of exposures across each demographic group. Each of these analyses should be considered independently of each other, as each was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses can be relevant for identifying populations that may be exposed to local environmental stressors, such as local NO_2 and SO_2 emitted from affected sources in this final rule, traffic, or noise. The baseline analysis indicates that on average the populations living within 10 kilometers of coal plants potentially impacted by the amended fPM standards have a higher percentage of people living below two times the poverty level than the national average. In addition, on average the percentage of the American Indian population living within 10 kilometers of lignite plants potentially impacted by the amended Hg standard is higher than the national average. Assessing these results, we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by the regulatory action (*e.g.,* SO_2) for various population groups in the baseline (question 1). However, as proximity to affected facilities does not capture variation in baseline exposure across communities, nor does it indicate that any exposures or impacts will occur, these results should not be interpreted as a direct measure of exposure or impact.

As HAP exposure results generated as part of the 2020 Residual Risk Review were below both the presumptive acceptable cancer risk threshold and noncancer health benchmarks and this regulation should further reduce exposure to HAP, there are no ''disproportionate and adverse effects'' of potential EJ concern. Therefore, we did not perform a quantitative EJ assessment of HAP risk. However, the potential reduction in non-Hg HAP metal emissions would likely reduce exposures to people living nearby coal plants potentially impacted by the amended fPM standards.

This rule is also expected to reduce emissions of direct $PM_{2.5}$, NO_X, and SO_2 nationally throughout the year. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$ and because NO_X is a precursor to ozone formation, reducing these emissions would impact human exposure. Quantitative ozone and $PM_{2.5}$ exposure analyses can provide insight into all three EJ questions, so they are performed to evaluate potential disproportionate impacts of this rulemaking. Even though both the proximity and exposure analyses can potentially improve understanding of baseline EJ concerns (question 1), the two should not be directly compared. This is because the demographic proximity analysis does not include air quality information and is based on current, not future, population information.

The baseline analysis of ozone and $PM_{2.5}$ concentration burden responds to question 1 from the EPA's EJ technical guidance more directly than the proximity analyses, as it evaluates a form of the environmental stressor targeted by the regulatory action. Baseline $PM_{2.5}$ and ozone exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic, Asian, those without a high school diploma, and the unemployed may experience higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian, residents of Tribal Lands, populations with higher life expectancy or with life expectancy data unavailable, children, and insured populations may also experience disproportionately higher ozone concentrations than the reference group. Hispanic, Black, below the poverty line, and uninsured populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group. Therefore, also in response to question 1, there likely are potential EJ concerns associated with ozone and $PM_{2.5}$ exposures affected by the regulatory action for population groups of concern in the baseline. However, these baseline exposure results have not been fully explored and additional analyses are likely needed to understand potential implications. Due to the small magnitude of the exposure changes across population demographics associated with the rulemaking relative to the magnitude of the baseline disparities, we infer that post-policy EJ ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action or alternative under consideration (question 2).

Question 3 asks whether potential EJ concerns will be created or mitigated as compared to the baseline. Due to the very small magnitude of differences across demographic population post-policy ozone and $PM_{2.5}$ exposure impacts, we do not find evidence that potential EJ concerns related to ozone and $PM_{2.5}$ concentrations will be created or mitigated as compared to the baseline.[103]

X. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This action is a ''significant regulatory action,'' as defined under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, *Regulatory Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review* (Ref. EPA–452/R–24–005), is briefly summarized in section IX. of this preamble and here. This analysis is also available in the docket.

Table 11 of this document presents the estimated PV and EAV of the monetizable projected health benefits, climate benefits, compliance costs, and net benefits of the final rule in 2019 dollars discounted to 2023. The estimated monetized net benefits are the projected monetized benefits minus the projected monetized costs of the final rule.

Under Executive Order 12866, the EPA is directed to consider all of the costs and benefits of its actions, not just those that stem from the regulated pollutant. Accordingly, the projected monetized benefits of the final rule include health benefits associated with projected reductions in $PM_{2.5}$ and ozone concentration. The projected monetized benefits also include climate benefits due to reductions in CO_2 emissions. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3, and 7 percent. The projected climate

---

[103] Please note that results for ozone and $PM_{2.5}$ exposures should not be extrapolated to other air pollutants that were not included in the assessment, including HAP. Detailed EJ analytical results can be found in section 6 of the RIA.

benefits in this table are based on estimates of the SC–CO$_2$ at a 2 percent near-term Ramsey discount rate and are discounted using a 2 percent discount rate to obtain the PV and EAV estimates in the table. The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and policy scenarios. In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the finalized requirements and represent the EPA's best estimate of the social cost of the final rulemaking.

BILLING CODE 6560–50–P

Table 11. Projected Monetized Benefits, Compliance Costs, and Net Benefits of the Final Rule, 2028 through 2037 (Millions 2019$, Discounted to 2023)[a]

	Present Value (PV)		
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	300	260	180
Climate Benefits[d]	130	130	130
Compliance Costs	860	790	560
Net Benefits	-440	-400	-260
	Equal Annualized Value (EAV)[b]		
	2% Discount Rate	3% Discount Rate	7% Discount Rate
Health Benefits[c]	33	31	25
Climate Benefits[d]	14	14	14
Compliance Costs	96	92	80
Net Benefits	-49	-47	-41
Non-Monetized Benefits[e]	Benefits from reductions of about 900 to 1000 pounds of Hg annually		
	Benefits from reductions of at least 4 to 7 tons of non-Hg HAP metals annually		
	Benefits from improved water quality and availability		
	Benefits from the increased transparency, compliance assurance, and accelerated identification of anomalous emission anticipated from requiring PM CEMS		

[a] Values have been rounded to two significant figures. Rows may not appear to sum correctly due to rounding.

[b] The EAV of costs and benefits are calculated over the 10-year period from 2028 to 2037.

[c] The projected monetized air quality related benefits include those related to public health associated with reductions in PM$_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3, and 7 percent.

[d] Monetized climate benefits are based on reductions in CO$_2$ emissions and are calculated using three different estimates of the SC-CO$_2$ (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO$_2$ at the 2 percent near-term Ramsey discount rate. Please see section 4 of the RIA for the full range of monetized climate benefit estimates.

[e] The list of non-monetized benefits does not include all potential non-monetized benefits. See table 4-8 of the RIA for a more complete list.

BILLING CODE 6560–50–C

As shown in table 11 of this document, this rule is projected to reduce PM$_{2.5}$ and ozone concentrations, producing a projected PV of monetized health benefits of about $300 million, with an EAV of about $33 million discounted at 2 percent. The rule is also projected to reduce greenhouse gas emissions in the form of CO$_2$, producing a projected PV of monetized climate benefits of about $130 million, with an EAV of about $14 million using the SC–$CO_2$ discounted at 2 percent. Thus, this final rule would generate a PV of monetized benefits of $420 million, with an EAV of $47 million discounted at a 2 percent rate. The PV of the projected compliance costs are $860 million, with an EAV of about $96 million discounted at 2 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of −$440 million and EAV of −$49 million.

At a 3 percent discount rate, this rule is expected to generate projected PV of monetized health benefits of $260 million, with an EAV of about $31 million. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, this final rule would generate a PV of monetized benefits of $390 million, with an EAV of $45 million discounted at a 3 percent rate. The PV of the projected compliance costs are $790 million, with an EAV of $92 million discounted at 3 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of −$400 million and an EAV of −$47 million.

At a 7 percent discount rate, this rule is expected to generate projected PV of monetized health benefits of $160 million, with an EAV of about $23 million. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, this final rule would generate a PV of monetized benefits of $300 million, with an EAV of $39 million discounted at a 3 percent rate. The PV of the projected compliance costs are $560 million, with an EAV of $80 million discounted at 7 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of −$260 million and an EAV of −$41 million.

The potential benefits from reducing Hg and non-Hg HAP metals and potential improvements in water quality and availability were not monetized and are therefore not directly reflected in the monetized benefit-cost estimates associated with this final rule. Potential benefits from the increased transparency and accelerated identification of anomalous emission anticipated from requiring CEMS were also not monetized in this analysis and are therefore also not directly reflected in the monetized benefit-cost comparisons. We nonetheless consider these impacts in our evaluation of the net benefits of the rule and find, if we were able to quantify and monetize these beneficial impacts, the final rule would have greater net benefits than shown in table 11 of this preamble.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2137–12. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0567.

The information collection activities in this rule include continuous emission monitoring, performance testing, notifications and periodic reports, recording information, monitoring and the maintenance of records. The information generated by these activities will be used by the EPA to ensure that affected facilities comply with the emission limits and other requirements. Records and reports are necessary to enable delegated authorities to identify affected facilities that may not be in compliance with the requirements. Based on reported information, delegated authorities will decide which units and what records or processes should be inspected. The recordkeeping requirements require only the specific information needed to determine compliance. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). The burden and cost estimates below represent the total burden and cost for the information collection requirements of the NESHAP for Coal- and Oil-Fired EGUs, not just the burden associated with the amendments in this final rule. The incremental cost associated with these amendments is $2.4 million per year.

Respondents/affected entities: The respondents are owners or operators of coal- and oil-fired EGUs. The North American Industry Classification System (NAICS) codes for the coal- and oil-fired EGU industry are 221112, 221122, and 921150.

Respondent's obligation to respond: Mandatory per 42 U.S.C. 7414 *et seq.*

Estimated number of respondents: 192 per year.[104]

Frequency of response: The frequency of responses varies depending on the burden item. Responses include daily calibrations, monthly recordkeeping activities, semiannual compliance reports, and annual reports.

Total estimated burden: 447,000 hours (per year). Burden is defined at 5 CFR part 1320.3(b).

Total estimated cost: $106,600,000 (per year), includes $53,100,000 in annual labor costs and $53,400,000 annualized capital and operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

The EPA certifies that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In the 2028 analysis year, the EPA identified 24 potentially affected small entities operating 45 units at 26 facilities, and of these 24, only one small entity may experience compliance cost increases greater than one percent of revenue under the final rule. Details of this analysis are presented in section 5 of the RIA, which is in the public docket.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more (adjusted for inflation) as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The costs involved in this action are estimated not to exceed $100 million or more (adjusted for inflation) in any one year.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive

---

[104] Each facility is a respondent and some facilities have multiple EGUs.

Order 13175. The Executive order defines tribal implications as ''actions that have substantial direct effects on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes.'' The amendments in this action would not have a substantial direct effect on one or more tribes, change the relationship between the Federal Government and tribes, or affect the distribution of power and responsibilities between the Federal Government and Indian tribes. Thus, Executive Order 13175 does not apply to this action.

Although this action does not have tribal implications as specified in Executive Order 13175, the EPA consulted with tribal officials during the development of this action. On September 1, 2022, the EPA sent a letter to all federally recognized Indian tribes initiating consultation to obtain input on this action. The EPA did not receive any requests for consultation from Indian tribes. The EPA also participated in the September 2022 National Tribal Air Association EPA Air Policy Update Call to solicit input on this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045 directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is subject to Executive Order 13045 because it is a significant regulatory action under section 3(f)(1) of Executive Order 12866. Accordingly, we have evaluated the potential for environmental health or safety effects from exposure to HAP, ozone, and $PM_{2.5}$ on children. The EPA believes that, even though the 2020 residual risk assessment showed all modeled exposures to HAP to be below thresholds for public health concern, the rule should reduce HAP exposure by reducing emissions of Hg and non-Hg HAP with the potential to reduce HAP exposure to vulnerable populations, including children. The action described in this rule is also expected to lower ozone and $PM_{2.5}$ in many areas, including those areas that struggle to attain or maintain the NAAQS, and thus mitigate some pre-existing health risks across all populations evaluated, including children. The results of this evaluation are contained in the RIA and are available in the docket for this action.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. For 2028, the compliance year for the standards, the EPA does not project a significant change in retail electricity prices on average across the contiguous U.S., coal-fired electricity generation, natural gas-fired electricity generation, or utility power sector delivered natural gas prices. Details of the projected energy effects are presented in section 3 of the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

The following standards appear in the amendatory text of this document and were previously approved for the locations in which they appear: ANSI/ASME PTC 19.10–1981, ASTM D6348–03(R2010), and ASTM D6784–16.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

The EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with environmental justice concerns. For this rule, we employ the proximity demographic analysis and the $PM_{2.5}$ and ozone exposure analyses to evaluate disproportionate and adverse human health and environmental effects on communities with EJ concerns that exist prior to the action. The proximity demographic analysis indicates that on average the population living within 10 kilometers of coal plants potentially impacted by the fPM standards have a higher percentage of people living below two times the poverty level than the national average. In addition, on average the percentage of the American Indian population living within 10 kilometers of lignite-fired plants potentially impacted by the Hg standard is higher than the national average. Baseline $PM_{2.5}$ and ozone and exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic, Asian, those without a high school diploma, and the unemployed may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian, residents of Tribal Lands, populations with higher life expectancy or with life expectancy data unavailable, children, and insured populations may also experience disproportionately higher ozone concentrations than the reference group. Hispanics, Blacks, those below the poverty line, and uninsured populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group.

The EPA believes that this action is not likely to change existing disproportionate and adverse effects on communities with environmental justice concerns. Only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns after implementation of the final rule, and whether potential EJ concerns will be created or mitigated. We infer that baseline disparities in ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the final regulatory option due to the small magnitude of the exposure changes across population demographics associated with the rulemaking relative to the baseline disparities. We also do not find evidence that potential EJ concerns related to ozone or $PM_{2.5}$ exposures will be exacerbated or mitigated in the final regulatory option, compared to the baseline due to the very small differences in the magnitude of post-policy ozone and $PM_{2.5}$ exposure impacts across demographic populations. Additionally, the potential reduction in Hg and non-Hg HAP metal emissions would likely reduce exposures to people living nearby coal plants potentially impacted by the amended fPM standards.

The information supporting this Executive Order review is contained in section IX.F. of this preamble and in section 6, Environmental Justice Impacts of the RIA, which is in the public docket (EPA–HQ–OAR–2018–0794).

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedures, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Michael S. Regan,
Administrator.

For the reasons set forth in the preamble, 40 CFR part 63 is amended as follows:

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. In § 63.14, paragraph (f)(1) is amended by removing the text ‘‘tables 4 and 5 to subpart UUUUU’’ and adding, in its place, the text ‘‘table 5 to subpart UUUUU’’.

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

■ 3. Section 63.9991 is amended by revising paragraph (a)(2) to read as follows:

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) * * *

(2) Before July 6, 2027, you must meet each operating limit in Table 4 to this subpart that applies to your EGU.

* * * * *

■ 4. Amend § 63.10000 by:
■ a. Revising paragraph (c)(1)(i) and paragraph (c)(1)(i)(A);
■ b. Redesignating paragraph (c)(1)(i)(C) as paragraph (c)(1)(i)(D);
■ c. Adding new paragraph (c)(1)(i)(C);
■ d. Revising paragraph (c)(1)(iv);
■ e. Adding new paragraphs (c)(1)(iv)(A) through (C);
■ f. Revising paragraphs (c)(2)(i) and (ii);
■ g. Revising paragraph (d)(5)(i); and
■ h. Revising paragraph (m) introductory text.

The revisions and additions read as follows:

§ 63.10000 What are my general requirements for complying with this subpart?

* * * * *

(c) * * *

(1) * * *

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct initial performance testing in accordance with § 63.10005(h), to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs (c)(1)(i)(A) through (C) of this section:

(A) Except as provided in paragraph (c)(1)(i)(D) of this section, you may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device.

* * * * *

(C) On or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals for coal-fired and solid oil-derived fuel-fired EGUs.

* * * * *

(iv)(A) Before July 6, 2027, if your coal-fired or solid oil derived fuel-fired EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

(B) On and after July 6, 2027, you may not pursue or continue to use the LEE option for your coal-fired or solid oil derived fuel-fired EGU for filterable PM or for non-mercury HAP metals. You must demonstrate compliance through an initial performance test, and you must monitor continuous performance with the applicable filterable PM emissions limit through the use of a PM CEMS or HAP metals CMS.

(C) If your IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable PM, you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

* * * * *

(2) * * *

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status. On or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals.

(ii) Before July 6, 2027, if your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly. On and after July 6, 2027, you may not pursue or continue to use the LEE option for your liquid oil-fired EGU for filterable PM or for non-mercury HAP metals. You must demonstrate compliance through an initial performance test, and you must monitor continuous performance with the applicable filterable PM emissions limit through the use of a PM CEMS or HAP metals CMS.

(d) * * *

(5) * * *

(i) Installation of the CMS or sorbent trap monitoring system 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). See § 63.10010(a) for further details. For PM CPMS installations (which with the exception of IGCC units, are only applicable before July 6, 2027), follow the procedures in § 63.10010(h).

* * * * *

(m) Should you choose to rely on paragraph (2) of the definition of ‘‘startup’’ in § 63.10042 for your EGU (only allowed before January 2, 2025), on or before the date your EGU is subject to this subpart, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with § 63.10020(e). On and after January 2, 2025 you will no longer be able to choose paragraph (2) of the ‘‘startup’’ definition in § 63.10042.

* * * * *

■ 5. Amend § 63.10005 by revising paragraphs (a)(1), (b) introductory text, (c), (d)(2) introductory text, (h) introductory text, and (h)(1) introductory text to read as follows:

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) * * *

(1) To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. Before July 6, 2027, if you are required to establish operating limits (see paragraph (d) of this section and Table 4 to this subpart), you must collect all applicable parametric data during the performance test period. On and after July 6, 2027, the requirements in Table 4 are not applicable, with the exception of IGCC units. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

* * * * *

(b) *Performance testing requirements.* If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to 40 CFR 63.10007 and Table 5 to this subpart. Notwithstanding these requirements, when Table 5 specifies the use of isokinetic EPA test Method 5, 5I, 5D, 26A, or 29 for a stack test, if concurrent measurement of the stack gas flow rate or moisture content is needed to convert the pollutant concentrations to units of the standard, separate determination of these parameters using EPA test Method 2 or EPA test Method 4 is not necessary. Instead, the stack gas flow rate and moisture content can be determined from data that are collected during the EPA test Method 5, 5I, 5D, 6, 26A, or 29 test (*e.g.,* pitot tube (delta P) readings, moisture collected in the impingers, etc.). For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in 40 CFR 63.9984, provided that the following conditions are fully met:

* * * * *

(c) *Operating limits.* In accordance with § 63.10010 and Table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration. With the exception of IGCC units, on and after July 6, 2027, you may not demonstrate compliance with applicable filterable PM emissions limits with the use of PM CPMS or quarterly stack testing, you may only use PM CEMS.

* * * * *

(d) * * *

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS (with the exception of IGCC units, the use of PM CPMS is only allowed before July 6, 2027):

* * * * *

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM. You may pursue this compliance option unless prohibited pursuant to § 63.10000(c)(1)(i).

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h) with the exception that on or after July 6, 2027, you may not pursue the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals for any existing, new or reconstructed EGUs (this does not apply to IGCC units), and if those data demonstrate:

* * * * *

■ 6. Amend § 63.10006 by revising paragraph (a) to read as follows:

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS before July 6, 2027 to monitor continuous performance with an applicable emission limit as provided for under § 63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and § 63.10007 at least every year. On or after July 6, 2027 you may not use PM CPMS to demonstrate compliance for liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs. This prohibition against the use of PM CPMS does not apply to IGCC units.

* * * * *

■ 7. Amend § 63.1007 by revising paragraphs (a)(3) and (c) to read as follows:

§ 63.10007 What methods and other procedures must I use for the performance tests?

(a) * * *

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non-Hg metals emissions limit (the use of PM CPMS is only allowed before July 6, 2027 with the exception of IGCC units), operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

* * * * *

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b), § 63.10023, and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits. On and after July 6, 2027, you must demonstrate continuous compliance with the applicable filterable PM emission standard through the use of a PM CEMS (with the exception that IGCC units are not required to use PM CEMS and may continue to use PM CPMS). Alternatively, you may demonstrate continuous compliance with the non-Hg metals emission standard if you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

* * * * *

■ 8. Amend § 63.10010 by revising paragraphs (a) introductory text, (h) introductory text, (i) introductory text, (j), and (l) introductory text to read as follows:

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS (which on or after July 6, 2027 you may not use PM CPMS for filterable PM compliance demonstrations unless it is for an IGCC unit), and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

* * * * *

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit (only applicable before July 6, 2027 unless it is for an IGCC unit), you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

* * * * *

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits (which on or after July 6, 2027 you may not use non-mercury metal HAP limits for compliance demonstrations for existing EGUs unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f)), you may choose to install, certify, operate, and maintain a PM CEMS and record and report the output of the PM CEMS as specified in paragraphs (i)(1) through (8) of this section. With the exception of IGCC units, on or after July 6, 2027 owners/operators of existing EGUs must comply with filterable PM emissions limits in Table 2 of this subpart and demonstrate continuous compliance using a PM CEMS unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f). Compliance with the applicable PM emissions limit in Table 1 or 2 to this subpart is determined on a 30-boiler operating day rolling average basis.

* * * * *

(j) You may choose to comply with the metal HAP emissions limits using CMS approved in accordance with § 63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CMS and record the output of the HAP metals CMS as specified in paragraphs (j)(1) through (5) of this section.

(1)(i) Install, calibrate, operate, and maintain your HAP metals CMS according to your CMS quality control program, as described in § 63.8(d)(2). The reportable measurement output from the HAP metals CMS must be expressed in units of the applicable emissions limit (*e.g.,* lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CMS according to the procedures and criteria in your site specific performance evaluation and quality control program plan required in § 63.8(d).

(2) Collect HAP metals CMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for required monitoring system quality assurance or quality control activities, and any scheduled maintenance as defined in your site-specific monitoring plan.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during periods of monitoring system malfunctions and repairs associated with monitoring system malfunctions. You must report any monitoring system malfunctions as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(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 quality control activities conducted during out-of-control periods. You must report any out of control periods as deviations in your compliance reports under 40 CFR 63.10031(c) or (g) (as applicable);

(C) Any data recorded during required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (*e.g.,* calibrations, certain audits, routine probe maintenance); and

(D) Any data recorded during periods of startup or shutdown.

(ii) You must record and report the results of HAP metals CMS system performance audits, in accordance with 40 CFR 63.10031(k). You must also record and make available upon request the dates and duration of periods when the HAP metals CMS is out of control to completion of the corrective actions necessary to return the HAP metals CMS to operation consistent with your site-specific performance evaluation and quality control program plan.

* * * * *

(l) Should you choose to rely on paragraph (2) of the definition of ‘‘startup’’ in § 63.10042 for your EGU (only allowed before January 2, 2025), you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with § 63.10020(e). On and after January 2, 2025 you will no longer be able to choose paragraph (2) of the ‘‘startup’’ definition in § 63.10042 for your EGU.

* * * * *

■ 9. Amend § 63.10011 by revising paragraphs (b), (g)(3), and (4) introductory text to read as follows:

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

* * * * *

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance (with the exception of existing IGCC units, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM limits and the Table 4 p.m. CPMS operating limits do not apply), or if, for an IGCC unit, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with § 63.10007 and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.,* tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit. On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM limits and the Table 6 procedures for establishing PM CPMS operating limits do not apply unless it is an IGCC unit.

* * * * *

(g) * * *

(3) You must report the emissions data recorded during startup and shutdown. If you are relying on paragraph (2) of the definition of startup in 40 CFR 63.10042 (only allowed before January 2, 2025), then for startup and shutdown incidents that occur on or prior to December 31, 2023, you must also report the applicable supplementary information in 40 CFR 63.10031(c)(5) in the semiannual compliance report. For startup and shutdown incidents that occur on or after January 1, 2024, you must provide the applicable information in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i).

(4) If you choose to use paragraph (2) of the definition of "startup" in § 63.10042 (only allowed before January 2, 2025), and you find that you are unable to safely engage and operate your particulate matter (PM) control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel, you may choose to rely on paragraph (1) of definition of "startup" in § 63.10042 or you may submit a request to use an alternative non-opacity emissions standard, as described below.

* * * * *

■ 10. Section 63.10020 is amended by revising paragraphs (e) introductory text and (e)(3)(i) introductory text to read as follows:

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

* * * * *

(e) Additional requirements during startup periods or shutdown periods if you choose to rely on paragraph (2) of the definition of "startup" in § 63.10042 for your EGU (only allowed before January 2, 2025).

* * * * *

(3) * * *

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit, or that has LEE status for filterable PM or total non-Hg HAP metals for non-liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CMS (except that unless it is for an IGCC unit, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM emissions limits, and you may not purse or continue to use the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals), you must:

* * * * *

■ 11. Section 63.10021 is amended by revising paragraphs (c) introductory text and (i) to read as follows:

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

* * * * *

(c) If you use PM CPMS data (only allowed before July 6, 2027 unless it is for an IGCC unit) to measure compliance with an operating limit in Table 4 to this subpart, 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 (*e.g.,* milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average. On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations unless it is for an IGCC unit.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad (Eq. 9)$$

Where:

Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30 boiler operating days.

* * * * *

(i) Before January 2, 2025, if you are relying on paragraph 2 of the definition of startup in 40 CFR 63.10042, you must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in your semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, you must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph 2 of the definition of startup in 40 CFR 63.10042.

■ 12. Section 63.10022 is amended by revising paragraphs (a)(2) and (3) to read as follows:

§ 63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) * * *

(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test. On or after July 6, 2027 you may not use PM CPMS for filterable PM compliance demonstrations unless it is for an IGCC unit;

(3) 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. Since on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit, for compliance demonstrations with the applicable filterable PM limits, the Table 4 p.m. CPMS operating limits do not apply.

* * * * *

■ 13. Section 63.10023 is amended by adding introductory text to the section to read as follows:

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

The provisions of this section § 63.10023 are only applicable before July 6, 2027 unless it is for an IGCC unit. On or after July 6, 2027 you may not use PM CPMS, unless it is an IGCC unit, for demonstrating compliance with the filterable PM emissions limits of this subpart.

* * * * *

■ 14. Section 63.10030 is amended by revising paragraphs (e)(3), (8) introductory text, and (8)(i) introductory text to read as follows:

§ 63.10030 What notifications must I submit and when?

* * * * *

(e) * * *

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (*e.g.,* use of PM CPMS—which on or after July 6, 2027—you may not use for filterable PM compliance demonstrations, unless it is for an IGCC unit); CEMS; or a sorbent trap monitoring system.

* * * * *

(8) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of ''startup'' in § 63.10042. On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.

(i) Before January 2, 2025 should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU, you shall include a report that identifies:

* * * * *

■ 15. Section 63.10031 is amended by revising paragraphs (a)(4), (c)(5) introductory text, (f)(2), (i), and (k) to read as follows:

§ 63.10031 What reports must I submit and when?

(a) * * *

(4) Before July 6, 2027, if you elect to demonstrate continuous compliance using a PM CPMS, you must meet the electronic reporting requirements of appendix D to this subpart. Except for IGCC units, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations. Electronic reporting of the hourly PM CPMS output shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS.

(c) * * *

(5) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (only allowed before January 2, 2025), for each instance of startup or shutdown you shall:

* * * * *

(f) * * *

(2) If, for a particular EGU or a group of EGUs serving a common stack, you have elected to demonstrate compliance using a PM CEMS, an approved HAP metals CMS, or a PM CPMS (on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit), you must submit quarterly PDF reports in accordance with paragraph (f)(6) of this section, which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in paragraph (g) of this section. In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CMS, the quarterly compliance reports described in paragraph (g) of this section must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO_2, if you have elected to (or are required to) continuously monitor these pollutants. Further, if your EGU or common stack is in an averaging plan, your quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group.

* * * * *

(i) If you have elected to use paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042 (only allowed before January 2, 2025), then, for startup and shutdown incidents that occur on or prior to December 31, 2023, you must include the information in 40 CFR 63.10031(c)(5) in the semiannual compliance report, in a PDF file. If you have elected to use paragraph (2) of the definition of ''startup'' in 40 CFR 63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, you must use the ECMPS Client Tool to submit the information in 40 CFR 63.10031(c)(5) and 40 CFR 63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into ECMPS with each startup and shutdown report.

* * * * *

(k) If you elect to demonstrate compliance using a PM CPMS (on or after July 6, 2027 you may not demonstrate compliance with filterable PM emissions limits using a PM CPMS, unless it is for an IGCC unit) or an approved HAP metals CMS, you must submit quarterly reports of your QA/QC activities (*e.g.,* calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CMS is used for the compliance demonstration in that quarter. Otherwise, submit a report for the first calendar quarter in which the PM CPMS or HAP metals CMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in paragraph (f)(6)(i) through (xii) of this section must be entered into ECMPS with the PDF report.

■ 16. Section 63.10032 is amended by revising paragraphs (a) introductory text and (f)(2) introductory text to read as follows:

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if you elect to use a PM CPMS (unless it is for an IGCC unit, you may only use PM CPMS before July 6, 2027), you must keep the records required under appendix A and/or appendix B and/or appendix C and/or appendix D to this subpart. If you elect to conduct periodic (*e.g.,* quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, you must keep records of the applicable data elements under 40 CFR 63.7(g). You must also keep records of all data elements and other information in appendix E to this subpart that apply to your compliance strategy.

* * * * *

(f) * * *

(2) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU (on or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042), you must keep records of:

* * * * *

■ 17. Section 63.10042 is amended by revising the definition ''Startup'' to read as follows:

§ 63.10042 What definitions apply to this subpart?

* * * * *

Startup means:

(1) The first-ever firing of fuel in a boiler for the purpose of producing

electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup.

(2) Alternatively, prior to January 2, 2025, the period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

* * * * *

■ 18. Revise table 1 to subpart UUUUU of part 63 to read as follows:

Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

As stated in § 63.9991, you must comply with the following applicable emission limits:

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh[1] ...	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn) ...	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	1.0E–2 lb/MWh	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 3 dscm per run. For ASTM D6348–03(Reapproved 2010)[2] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3].	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal ...	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh[1] ...	Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn) ...	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run For ASTM D6348–03(Reapproved 2010)[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3].	1.0 lb/MWh	SO_2 CEMS.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	c. Mercury (Hg)	Before July 8, 2024: 4.0E–2 lb/GWh; On or after July 8, 2024: 1.3E–2 lb/GWh.	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh [4] 9.0E–2 lb/MWh [5].	Collect a minimum catch of 3.0 milligrams or a minimum sample volume of 2 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	4.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E–2 lb/GWh.	
	Arsenic (As)	2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	4.0E–2 lb/GWh.	
	Cobalt (Co)	4.0E–3 lb/GWh.	
	Lead (Pb)	9.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	7.0E–2 lb/GWh.	
	Selenium (Se)	3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26 at appendix A–8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348–03(Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3].	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E–4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E–2 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	5.0E–4 lb/GWh.	
	Cadmium (Cd)	2.0E–4 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E–2 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	1.0E–4 lb/GWh	For Method 30B at appendix A–8 to part 60 of this chapter sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03(Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF).	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	2.0E–1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E–3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Arsenic (As)	6.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–1 lb/GWh.	
	Lead (Pb)	3.0E–2 lb/GWh.	
	Manganese (Mn)	1.0E–1 lb/GWh.	
	Nickel (Ni)	4.1E0 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF).	5.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	3.0E–2 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals.	6.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:.		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	7.0E–4 lb/GWh.	
	Chromium (Cr)	6.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	7.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl).	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010) [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3].	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross output.

[2] Incorporated by reference, see § 63.14.

[3] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO_2 CEMS installed.

[4] Duct burners on syngas; gross output.

[5] Duct burners on natural gas; gross output.

■ 19. Revise table 2 to subpart UUUUU of part 63 to read as follows:

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

As stated in § 63.9991, you must comply with the following applicable emission limits: [1]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM).	Before July 6, 2027: 3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Before July 6, 2027: Collect a minimum of 1 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
		On or after July 6, 2027: 1.0E–2 lb/MMBtu or 1.0E–1 lb/MWh[2].	On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	Before July 6, 2027: 5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh. On or after July 6, 2027: 1.7E–5 lb/MMBtu or 1.7E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Arsenic (As)	Before July 6, 2027: 1.1E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 3.7E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Beryllium (Be)	Before July 6, 2027: 2.0E–1 lb/TBtu or 2.0E–3 lb/GWh. On or after July 6, 2027: 6.7E–2 lb/TBtu or 6.7E–4 lb/GWh.	
	Cadmium (Cd)	Before July 6, 2027: 3.0E–1 lb/TBtu or 3.0E–3 lb/GWh. On or after July 6, 2027: 1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/TBtu or 3.0E–2 lb/GWh. On or after July 6, 2027: 9.3E–1 lb/TBtu or 1.0E–2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Cobalt (Co)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Lead (Pb)	Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 4.0E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Manganese (Mn)	Before July 6, 2027: 4.0E0 lb/TBtu or 5.0E–2 lb/GWh. On or after July 6, 2027: 1.3E0 lb/TBtu or 1.7E–2 lb/GWh.	
	Nickel (Ni)	Before July 6, 2027: 3.5E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	
	Selenium (Se)	Before July 6, 2027: 5.0E0 lb/TBtu or 6.0E–2 lb/GWh. On or after July 6, 2027: 1.7E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[4].	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A–8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
		OR	
		1.0E0 lb/TBtu or 1.1E–2 lb/GWh.	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal	a. Filterable particulate matter (PM).	Before July 6, 2027: 3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh[2]. On or after July 6, 2027: 1.0E–2 lb/MMBtu or 1.0E–1 lb/MWh[2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	Before July 6, 2027: 5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh. On or after July 6, 2027: 1.7E–5 lb/MMBtu or 1.7E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Arsenic (As)	Before July 6, 2027: 1.1E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 3.7E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Beryllium (Be)	Before July 6, 2027: 2.0E–1 lb/TBtu or 2.0E–3 lb/GWh. On or after July 6, 2027: 6.7E–2 lb/TBtu or 6.7E–4 lb/GWh.	
	Cadmium (Cd)	Before July 6, 2027: 3.0E–1 lb/TBtu or 3.0E–3 lb/GWh. On or after July 6, 2027: 1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/TBtu or 3.0E–2 lb/GWh. On or after July 6, 2027: 9.3E–1 lb/TBtu or 1.0E–2 lb/GWh.	
	Cobalt (Co)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Lead (Pb)	Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 4.0E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Manganese (Mn)	Before July 6, 2027: 4.0E0 lb/TBtu or 5.0E–2 lb/GWh. On or after July 6, 2027: 1.3E0 lb/TBtu or 1.7E–2 lb/GWh.	
	Nickel (Ni)	Before July 6, 2027: 3.5E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	
	Selenium (Se)	Before July 6, 2027: 5.0E0 lb/TBtu or 6.0E–2 lb/GWh. On or after July 6, 2027: 1.7E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26 at appendix A–8 to part 60 of this chapter, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO_2)[4].	OR 2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	Before July 6, 2027: 4.0E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh[2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 3.0 milligrams or a minimum sample volume of 2 dscm per run.
	OR Total non-Hg HAP metals.	OR 6.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:.	OR	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Cadmium (Cd)	1.5E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E–2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh.	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E–2 lb/GWh.	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl).	5.0E–4 lb/MMBtu or 5.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh[2].	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total HAP metals	8.0E–4 lb/MMBtu or 8.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E–1 lb/GWh.	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E–2 lb/GWh.	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh.	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	2.0E–3 lb/MMBtu or 1.0E–2 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF).	4.0E–4 lb/MMBtu or 4.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh[2].	Collect a minimum of 1 dscm per run.

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total HAP metals ..	6.0E–4 lb/MMBtu or 7.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Beryllium (Be)	6.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh.	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn) ...	2.0E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh.	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Mercury (Hg)	4.0E–2 lb/TBtu or 4.0E–4 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl).	2.0E–4 lb/MMBtu or 2.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF).	6.0E–5 lb/MMBtu or 5.0E–4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	8.0E–3 lb/MMBtu or 9.0E–2 lb/MWh[2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	4.0E–5 lb/MMBtu or 6.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 7.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–1 lb/TBtu or 5.0E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Beryllium (Be)	6.0E–2 lb/TBtu or 5.0E–4 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 4.0E–3 lb/GWh.	
	Chromium (Cr)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Selenium (Se)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	5.0E–3 lb/MMBtu or 8.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320, sample for a minimum of 1 hour.
	OR	OR	
	Sulfur dioxide (SO$_2$)[4].	3.0E–1 lb/MMBtu or 2.0E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
7. Eastern Bituminous Coal Refuse (EBCR)-fired unit.	a. Filterable particulate matter (PM).	Before July 6, 2027: 3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh[2]. On or after July 6, 2027: 1.0E–2 lb/MMBtu or 1.0E–1 lb/MWh[2].	Before July 6, 2027: Collect a minimum of 1 dscm per run. On or after July 6, 2027: Collect a minimum catch of 6.0 milligrams or a minimum sample volume of 4 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following total non-Hg HAP metals emission limit if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Total non-Hg HAP metals.	Before July 6, 2027: 5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh. On or after July 6, 2027: 1.7E–5 lb/MMBtu or 1.7E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	On or after July 6, 2027 you may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).
	Individual HAP metals:.	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Arsenic (As)	Before July 6, 2027: 1.1E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 3.7E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Beryllium (Be)	Before July 6, 2027: 2.0E–1 lb/TBtu or 2.0E–3 lb/GWh. On or after July 6, 2027: 6.7E–2 lb/TBtu or 6.7E–4 lb/GWh.	
	Cadmium (Cd)	Before July 6, 2027: 3.0E–1 lb/TBtu or 3.0E–3 lb/GWh. On or after July 6, 2027: 1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Chromium (Cr)	Before July 6, 2027: 2.8E0 lb/TBtu or 3.0E–2 lb/GWh. On or after July 6, 2027: 9.3E–1 lb/TBtu or 1.0E–2 lb/GWh.	
	Cobalt (Co)	Before July 6, 2027: 8.0E–1 lb/TBtu or 8.0E–3 lb/GWh. On or after July 6, 2027: 2.7E–1 lb/TBtu or 2.7E–3 lb/GWh.	
	Lead (Pb)	Before July 6, 2027: 1.2E0 lb/TBtu or 2.0E–2 lb/GWh. On or after July 6, 2027: 4.0E–1 lb/TBtu or 6.7E–3 lb/GWh.	
	Manganese (Mn)	Before July 6, 2027: 4.0E0 lb/TBtu or 5.0E–2 lb/GWh. On or after July 6, 2027: 1.3E0 lb/TBtu or 1.7E–2 lb/GWh.	
	Nickel (Ni)	Before July 6, 2027: 3.5E0 lb/TBtu or 4.0E–2 lb/GWh. On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
	Selenium (Se)	Before July 6, 2027: 5.0E0 lb/TBtu or 6.0E–2 lb/GWh. On or after July 6, 2027: 1.7E0 lb/TBtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh.	For Method 26A at appendix A–8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 (Reapproved 2010)[3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[4].	6E–1 lb/MMBtu or 9E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh.	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A–8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
	OR		
		1.0E0 lb/TBtu or 1.1E–2 lb/GWh.	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of 2. With the exception of IGCC units, on or after July 6, 2027 you may not pursue the LEE option for filterable PM, total non-Hg metals, and individual HAP metals and you may not comply with the total non-Hg HAP metals or individual HAP metals emissions limits for all existing EGU subcategories unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

[2] Gross output.

[3] Incorporated by reference, *see* § 63.14.

[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

■ 20. Revise table 3 to subpart UUUUU of part 63 to read as follows:

Table 3 to Subpart UUUUU of Part 63—Work Practice Standards

As stated in § 63.9991, you must comply with the following applicable work practice standards:

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup.	a. Before January 2, 2025 you have the option of complying using either of the following work practice standards in paragraphs (1) and (2). On or after January 2, 2025 you may not choose to use paragraph (2) of the definition of startup in § 63.10042 and the following associated work practice standards in paragraph (2).

If your EGU is . . .	You must meet the following . . .
	(1) If you choose to comply using paragraph (1) of the definition of “startup” in § 63.10042, you must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels as defined in § 63.10042 for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this subpart. You must keep records during startup periods. You must provide reports concerning activities and startup periods, as specified in § 63.10011(g) and § 63.10021(h) and (i). If you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). (2) If you choose to comply using paragraph (2) of the definition of “startup” in § 63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup. For startup of an EGU, you must use one or a combination of the clean fuels defined in § 63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in § 63.10020(e). Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits beginning with the hour after startup ends. You must engage and operate your PM control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel. You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this subpart that require operation of the control devices. b. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods. d. You must collect monitoring data during startup periods, as specified in § 63.10020(a) and (e). You must keep records during startup periods, as provided in §§ 63.10021(h) and 63.10032. You must provide reports concerning activities and startup periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031. Before January 2, 2025, if you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.
4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown.	You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this subpart and that require operation of the control devices. 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 clean fuels defined in § 63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator.

If your EGU is . . .	You must meet the following . . .
	You must comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in § 63.10020(a). You must keep records during shutdown periods, as provided in §§ 63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031. Before January 2, 2025, if you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i). On or after January 2, 2025 you may not use paragraph (2) of the definition of startup in § 63.10042.

■ 21. Revise table 4 to subpart UUUUU of part 63 to read as follows:

Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

Before July 6, 2027, as stated in § 63.9991, you must comply with the applicable operating limits in table 4. However, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit.

If you demonstrate compliance using . . .	You must meet these operating limits . . .
PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

■ 22. Revise table 5 to subpart UUUUU of part 63 to read as follows:

Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements

As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:[1]

BILLING CODE 6560–50–P

To conduct a performance test for the following pollutant . . .	**Using . . .**	**You must perform the following activities, as applicable to your input- or output-based emission limit . . .**	**Using . . .**[2]
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Methods 5 and 5I at appendix A-3 to part 60 of this chapter. For positive pressure fabric filters, Method 5D at appendix A-3 to part 60 of this chapter for filterable PM emissions. Note that the Method 5 or 5I front half temperature shall be 160° ±14 °C (320° ±25 °F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	PM CEMS	a. Install, certify, operate, and	Performance Specification 11 at appendix B to part 60 of this chapter and Procedure 2 at appendix F to part 60 of this chapter.

		maintain the PM CEMS	
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine	Method 29 at appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at appendix A-8 to part 60 of this chapter; for Method 29, you must

		each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration	report the front half and back half results separately. When using Method 29, report metals matrix spike and recovery levels.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the HCl and HF	Method 26 or Method 26A at appendix A-8 to part 60 of this chapter or Method 320 at

		emissions concentrations	appendix A to part 63 of this chapter or ASTM D6348-03 Reapproved 2010[3] with
			(1) the following conditions when using ASTM D6348-03 Reapproved 2010:
			(A) The test plan preparation and implementation in the Annexes to ASTM D6348-03 Reapproved 2010, Sections A1 through A8 are mandatory;
			(B) For ASTM D6348-03 Reapproved 2010 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);
			(C) For the ASTM D6348-03 Reapproved 2010 test data to be acceptable for a target analyte, %R must be 70% ≥R ≤130%; and
			(D) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation: $\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R}\, x\, 100$
			(2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit.
			Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).

		monitoring systems	
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter, ASTM D6784,[3] or Method 29 at appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
	OR	OR	
	Hg CEMS	a. Install, certify, operate, and	Sections 3.2.1 and 5.1 of appendix A of this subpart.

		maintain the CEMS	
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of appendix A to this subpart.
	OR	OR	
	Sorbent trap monitoring system	a. Install, certify, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh	Section 6 of appendix A to this subpart.

		emissions rates	
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G, or 2H at appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981,[3] or diluent gas monitoring systems certified according to part 75 of this chapter.
		d. Measure the moisture content of the stack gas	Method 4 at appendix A-3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.,* per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 29.0 lb/year threshold	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.

5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and § 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and § 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and gross output data (see § 63.10007(e)).

BILLING CODE 6560–50–C

[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and 63.10021(h). With the exception of IGCC units, on or after July 6, 2027: You may not use quarterly performance emissions testing to demonstrate compliance with the filterable PM emissions standards and for existing EGUs you may not choose to comply with the total or individual HAP metals emissions limits unless you request and receive approval for the use of a HAP metals CMS under § 63.7(f).

[2] See tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.

[3] Incorporated by reference, see § 63.14.

■ 23. Revise table 6 to subpart UUUUU of part 63 to read as follows:

Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits

Before July 6, 2027, as stated in § 63.10007, you must comply with the following requirements for establishing operating limits in table 6. However, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit.

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an EGU.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

■ 24. Revise table 7 to subpart UUUUU of part 63 to read as follows:

Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg.	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit. (On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit.).	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average of all of the quality assured hourly average PM CPMS output data (*e.g.,* milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring.	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in Table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in Table 2. (On or after July 6, 2027 you may not use quarterly performance testing for filterable PM compliance demonstrations, unless it is for an IGCC unit.).	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup.	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown.	Operating in accordance with Table 3.

■ 25. Revise table 8 to subpart UUUUU of part 63 to read as follows:

Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

[In accordance with 40 CFR 63.10031, you must meet the following reporting requirements, as they apply to your compliance strategy]

You must submit the following reports . . .
1. The electronic reports required under 40 CFR 63.10031 (a)(1), if you continuously monitor Hg emissions.
2. The electronic reports required under 40 CFR 63.10031 (a)(2), if you continuously monitor HCl and/or HF emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
3. The electronic reports required under 40 CFR 63.10031(a)(3), if you continuously monitor PM emissions.
Reporting of hourly PM emissions data using ECMPS shall begin with the first operating hour after: January 1, 2024, or the hour of completion of the initial PM CEMS correlation test, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
4. The electronic reports required under 40 CFR 63.10031(a)(4), if you elect to use a PM CPMS (on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit).
Reporting of hourly PM CPMS response data using ECMPS shall begin with the first operating hour after January 1, 2024, or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS, whichever is later.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
5. The electronic reports required under 40 CFR 63.10031(a)(5), if you continuously monitor SO_2 emissions.
Where applicable, these reports are due no later than 30 days after the end of each calendar quarter.
6. PDF reports for all performance stack tests completed prior to January 1, 2024 (including 30- or 90-boiler operating day Hg LEE test reports and PM test reports to set operating limits for PM CPMS), according to the introductory text of 40 CFR 63.10031(f) and 40 CFR 63.10031(f)(6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.
For a PM test that is used to set an operating limit for a PM CPMS, the report must also include the information in 40 CFR 63.10023(b)(2)(vi).
For each performance stack test completed on or after January 1, 2024, submit the test results in the relevant quarterly compliance report under 40 CFR 63.10031(g), together with the applicable reference method information in sections 17 through 31 of appendix E to this subpart.
7. PDF reports for all RATAs of Hg, HCl, HF, and/or SO_2 monitoring systems completed prior to January 1, 2024, and for correlation tests, RRAs and/or RCAs of PM CEMS completed prior to January 1, 2024, according to 40 CFR 63.10031(f)(1) and (6).
For each test, submit the PDF report no later than 60 days after the date on which testing is completed.
For each SO_2 or Hg system RATA completed on or after January 1, 2024, submit the electronic test summary required by appendix A to this subpart or part 75 of this chapter (as applicable) together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart, either prior to or concurrent with the relevant quarterly emissions report.

You must submit the following reports . . .
For each HCl or HF system RATA, and for each correlation test, RRA, and RCA of a PM CEMS completed on or after January 1, 2024, submit the electronic test summary in accordance with section 11.4 of appendix B to this subpart or section 7.2.4 of appendix C to this part, as applicable, together with the applicable reference method information in sections 17 through 30 of appendix E to this subpart.
8. Quarterly reports, in PDF files, that include all 30-boiler operating day rolling averages in the reporting period derived from your PM CEMS, approved HAP metals CMS, and/or PM CPMS (on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit), according to 40 CFR 63.10031(f)(2) and (6). These reports are due no later than 60 days after the end of each calendar quarter.
The final quarterly rolling averages report in PDF files shall cover the fourth calendar quarter of 2023.
Starting with the first quarter of 2024, you must report all 30-boiler operating day rolling averages for PM CEMS, approved HAP metals CMS, PM CPMS, Hg CEMS, Hg sorbent trap systems, HCl CEMS, HF CEMS, and/or SO_2 CEMS (or 90-boiler operating day rolling averages for Hg systems), in XML format, in the quarterly compliance reports required under 40 CFR 63.10031(g).
If your EGU or common stack is in an averaging plan, each quarterly compliance report must identify the EGUs in the plan and include all of the 30- or 90-group boiler operating day WAERs for the averaging group.
The quarterly compliance reports must be submitted no later than 60 days after the end of each calendar quarter.
9. The semiannual compliance reports described in 40 CFR 63.10031(c) and (d), in PDF files, according to 40 CFR 63.10031(f)(4) and (6). The due dates for these reports are specified in 40 CFR 63.10031(b).
The final semiannual compliance report shall cover the period from July 1, 2023, through December 31, 2023.
10. Notifications of compliance status, in PDF files, according to 40 CFR 63.10031(f)(4) and (6) until December 31, 2023, and according to 40 CFR 63.10031(h) thereafter.
11. Quarterly electronic compliance reports, in accordance with 40 CFR 63.10031(g), starting with a report for the first calendar quarter of 2024. The reports must be in XML format and must include the applicable data elements in sections 2 through 13 of appendix E to this subpart.
These reports are due no later than 60 days after the end of each calendar quarter.
12. Quarterly reports, in PDF files, that include the applicable information in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) pertaining to startup and shutdown events, starting with a report for the first calendar quarter of 2024, if you have elected to use paragraph 2 of the definition of startup in 40 CFR 63.10042 (see 40 CFR 63.10031(i)). On or after January 2, 2025 you may not use paragraph 2 of the definition of startup in 40 CFR 63.10042.
These PDF reports shall be submitted no later than 60 days after the end of each calendar quarter, along with the quarterly compliance reports required under 40 CFR 63.10031(g).
13. A test report for the PS 11 correlation test of your PM CEMS, in accordance with 40 CFR 63.10031(j).
If, prior to November 9, 2020, you have begun using a certified PM CEMS to demonstrate compliance with this subpart, use the ECMPS Client Tool to submit the report, in a PDF file, no later than 60 days after that date.
For correlation tests completed on or after November 9, 2020, but prior to January 1, 2024, submit the report, in a PDF file, no later than 60 days after the date on which the test is completed.
For correlation tests completed on or after January 1, 2024, submit the test results electronically, according to section 7.2.4 of appendix C to this subpart, together with the applicable reference method data in sections 17 through 31 of appendix E to this subpart.
14. Quarterly reports that include the QA/QC activities for your PM CPMS (on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit) or approved HAP metals CMS (as applicable), in PDF files, according to 40 CFR 63.10031(k).
The first report shall cover the first calendar quarter of 2024, if the PM CPMS or HAP metals CMS is in use during that quarter. Otherwise, reporting begins with the first calendar quarter in which the PM CPMS or HAP metals CMS is used to demonstrate compliance.
These reports are due no later than 60 days after the end of each calendar quarter.

■ 26. In appendix C to subpart UUUUU:

■ a. Revise sections 1.2, 1.3, 4.1, and 4.1.1.

■ b. Add sections 4.1.1.1 and 4.2.3.

■ c. Revise sections 5.1.1, 5.1.4, and the section heading for section 6.

The revisions and additions read as follows:

Appendix C to Subpart UUUUU of Part 63—PM Monitoring Provisions

1. General Provisions

* * * * *

1.2 *Initial Certification and Recertification Procedures.* You, as the owner or operator of an affected EGU that uses a PM CEMS to demonstrate compliance with a filterable PM emissions limit in Table 1 or 2 to this subpart must certify and, if applicable, recertify the CEMS according to Performance Specification 11 (PS–11) in appendix B to part 60 of this chapter. Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in PS–11, the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

1.3 *Quality Assurance and Quality Control Requirements.* You must meet the applicable quality assurance requirements of Procedure 2 in appendix F to part 60 of this chapter. Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in Procedure 2, the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

* * * * *

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* You must certify your PM CEMS and the other CMS used to determine compliance with the applicable emissions standard before the PM CEMS can be used to provide data under this subpart. However, if you have developed and are using a correlation curve, you may continue to use that curve, provided it continues to meet the acceptance criteria in PS–11 and Procedure 2 as discussed below. Redundant backup monitoring systems (if used) are subject to the same certification requirements as the primary systems.

4.1.1 PM CEMS. You must certify your PM CEMS according to PS–11 in appendix B to part 60 of this chapter. A PM CEMS that has been installed and certified according to PS–11 as a result of another state or federal regulatory requirement or consent decree prior to the effective date of this subpart shall be considered certified for this subpart if you can demonstrate that your PM CEMS meets the acceptance criteria in PS–11 and Procedure 2 in appendix F to part 60 of this chapter.

4.1.1.1 Beginning on July 6, 2027, when determining if your PM CEMS meets the acceptance criteria in PS–11 and Procedure 2 the value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, in the calculations.

* * * * *

4.2 Recertification.

* * * * *

4.2.3 Beginning on July 6, 2027 you must use the value of 0.015 lb/MMBtu in place of the applicable emission standard, or emission limit, in the calculations when determining if your PM CEMS meets the acceptance criteria in PS–11 and Procedure 2.

* * * * *

5. Ongoing Quality Assurance (QA) and Data Validation

* * * * *

5.1.1 Required QA Tests. Following initial certification, you must conduct periodic QA testing of each primary and (if applicable) redundant backup PM CEMS. The required QA tests and the criteria that must be met are found in Procedure 2 of appendix F to part 60 of this chapter

(Procedure 2). Except as otherwise provided in section 5.1.2 of this appendix, the QA tests shall be done at the frequency specified in Procedure 2.

* * * * *

5.1.4 RCA and RRA Acceptability. The results of your RRA or RCA are considered acceptable provided that the criteria in section 10.4(5) of Procedure 2 in appendix F to part 60 of this chapter are met for an RCA or section 10.4(6) of Procedure 2 in appendix F to part 60 of this chapter are met for an RRA. However, beginning on July 6, 2027 a value of 0.015 lb/MMBtu is to be used in place of the applicable emission standard, or emission limit, when determining whether the RCA and RRA are acceptable.

* * * * *

6. Data Reduction and Calculations

* * * * *

■ 27. Appendix D to subpart UUUUU of part 63 is amended by adding introductory text to the appendix to read as follows:

Appendix D to Subpart UUUUU of Part 63—PM CPMS Monitoring Provisions

On or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM emissions limits, unless it is for an IGCC unit.

* * * * *

[FR Doc. 2024–09148 Filed 5–6–24; 8:45 am]

BILLING CODE 6560–50–P

TABLE 4 TO SUBPART RRRa OF PART 60—CALIBRATION AND QUALITY CONTROL REQUIREMENTS FOR CONTINUOUS PARAMETER MONITORING SYSTEM (CPMS)—Continued

If you monitor this parameter . . .	Your accuracy requirements are . . .	And your calibration requirements are . . .
2. Flow Rate	a. ±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 rate. b. ±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 rate. c. ±5 percent over the normal range measured for mass flow rate.	d. Performance evaluation annually and following any period of more than 24 hours throughout which the flow rate exceeded the maximum rated flow rate of the sensor, or the data recorder was off scale. e. Checks of all mechanical connections for leakage monthly. f. Visual inspections and checks of CPMS operation every 3 months, unless the CPMS has a redundant flow sensor. g. Selection of a representative measurement location where swirling flow or abnormal velocity distributions due to upstream and downstream disturbances at the point of measurement are minimized.
pH	a. ±0.2 pH units	b. Performance evaluation annually. Conduct a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit. c. Visual inspections and checks of CPMS operation every 3 months, unless the CPMS has a redundant pH sensor. d. Select a measurement location that provides a representative sample of scrubber effluent and that ensures the fluid is properly mixed.
4. Specific Gravity	a. ±0.02 specific gravity units	b. Performance evaluation annually. c. Visual inspections and checks of CPMS operation every 3 months, unless the CPMS has a redundant specific gravity sensor. d. Select a measurement location that provides a representative sample of specific gravity of the absorbing liquid effluent and that ensures the fluid is properly mixed.

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 40. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 41. Amend § 63.14 by:
■ a. Revising paragraphs (a), (c), and (f), and (i) introductory text;
■ b. Redesignating paragraphs (i)(33) through (91) as (i)(34) through (92);
■ c. Adding new paragraph (i)(33);
■ d. Revising newly redesignated paragraphs (i)(89) and (96);
■ e. Removing note 1 to paragraph (i);
■ f. Revising and republishing paragraph (o); and
■ g. Revising paragraph (u).

The revisions, addition, and republication read as follows:

§ 63.14 Incorporations by reference.

(a)(1) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the U.S. Environmental Protection Agency (EPA) must publish a document in the **Federal Register** and the material must be available to the public. All approved incorporation by reference (IBR) material is available for inspection at the EPA and at the National Archives and Records Administration (NARA). Contact the EPA at: EPA Docket Center, Public Reading Room, EPA WJC West, Room 3334, 1301 Constitution Ave. NW, Washington, DC; phone: (202) 566–1744. For information on the availability of this material at NARA, visit *www.archives.gov/federal-register/cfr/ibr-locations* or email *fr.inspection@nara.gov.*

(2) The IBR material may be obtained from the sources in the following paragraphs of this section or from one or more private resellers listed in this paragraph (a)(2). For material that is no longer commercially available, contact: the EPA (see paragraph (a)(1) of this section).

(i) Accuris Standards Store, 321 Inverness Drive, South Englewood, CO, 80112; phone: (800) 332–6077; website: *https://store.accuristech.com.*

(ii) American National Standards Institute (ANSI), 25 West 43rd Street, Fourth Floor, New York, NY 10036–7417; phone: (212) 642–4980; email: *info@ansi.org*; website: *www.ansi.org.*

(iii) GlobalSpec, 257 Fuller Road, Suite NFE 1100, Albany, NY 12203–3621; phone: (800) 261–2052; website: *https://standards.globalspec.com.*

(iv) Nimonik Document Center, 401 Roland Way, Suite 224, Oakland, CA, 94624; phone (650) 591–7600; email: *info@document-center.com*; website: *www.document-center.com.*

(v) Techstreet, phone: (855) 999–9870; email: *store@techstreet.com*; website: *www.techstreet.com.*

* * * * *

(c) American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001; phone: (202) 682–8000; website: *www.api.org.*

(1) API Publication 2517, Evaporative Loss from External Floating-Roof Tanks, Third Edition, February 1989; IBR approved for §§ 63.111; 63.1402; 63.2406; 63.7944.

(2) API Publication 2518, Evaporative Loss from Fixed-roof Tanks, Second Edition, October 1991; IBR approved for § 63.150(g).

(3) API Manual of Petroleum Measurement Specifications (MPMS) Chapter 19.2 (API MPMS 19.2), Evaporative Loss From Floating-Roof Tanks, First Edition, April 1997; IBR approved for §§ 63.1251; 63.12005.

(4) API Manual of Petroleum Measurement Specifications (MPMS) Chapter 19.2 (API MPMS 19.2), Evaporative Loss From Floating-Roof Tanks, Fourth Edition, August 2020; IBR approved for § 63.101(b).

* * * * *

(f) American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016–5990; phone: (800) 843–2763; email: *CustomerCare@asme.org*; website: *www.asme.org*.

(1) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], issued August 31, 1981, IBR approved for §§ 63.116(c) and (h); 63.128(a); 63.145(i); 63.309(k); 63.365(b); 63.457(k); 63.490(g); 63.772(e) and (h); 63.865(b); 63.997(e); 63.1282(d) and (g); 63.1625(b); table 5 to subpart EEEE; §§ 63.3166(a); 63.3360(e); 63.3545(a); 63.3555(a); 63.4166(a); 63.4362(a); 63.4766(a); 63.4965(a); 63.5160(d); table 4 to subpart UUUU; table 3 to subpart YYYY; §§ 63.7822(b); 63.7824(e); 63.7825(b); 63.8000(d); 63.9307(c); 63.9323(a); 63.9621(b) and (c); 63.11148(e); 63.11155(e); 63.11162(f); 63.11163(g); 63.11410(j); 63.11551(a); 63.11646(a); 63.11945; table 4 to subpart AAAAA; table 5 to subpart DDDDD; table 4 to subpart JJJJJ; table 4 to subpart KKKKK; table 4 to subpart SSSSS; tables 4 and 5 to subpart UUUUU; table 1 to subpart ZZZZZ; table 4 to subpart JJJJJJ.

(2) [Reserved]

* * * * *

(i) ASTM International, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–2959; phone: (800) 262–1373; website: *www.astm.org*.

* * * * *

(33) ASTM D2879–23, Standard Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved December 1, 2023; IBR approved for § 63.101(b).

* * * * *

(89) ASTM D6348–12 (Reapproved 2020), Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, approved December 1, 2020; IBR approved for §§ 63.109(a); 63.365(b); 63.509(a); 63.7825(g) and (h).

* * * * *

(96) ASTM D6420–18, Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, approved November 1, 2018; IBR approved for §§ 63.101(b); 63.115(g); 63.116(c); 63.126(d); 63.128(a); 63.139(c); 63.145(d) and (i); 63.150(g); 63.180(d); 63.482(b); 63.485(t); 63.488(b); 63.490(c) and (e); 63.496(b); 63.500(c); 63.501(a); 63.502(j); 63.503(a) and(g); 63.525(a) and (e); 63.987(b); 63.997(e); 63.2354(b;, table 5 to subpart EEEE; §§ 63.2450(j); 63.8000(d).

* * * * *

(o) U.S. Environmental Protection Agency (EPA), 1200 Pennsylvania Avenue NW, Washington, DC 20460; phone: (202) 272–0167; website: *www.epa.gov/aboutepa/forms/contact-epa*.

(1) EPA–453/R–08–002, Protocol for Determining the Daily Volatile Organic Compound Emission Rate of Automobile and Light-Duty Truck Primer-Surfacer and Topcoat, published September 2008; IBR approved for §§ 63.3130(c); 63.3161(d) and (g); 63.3165(e); appendix A to subpart IIII.

(2) EPA–453/R–01–005, National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants—Background Information for Proposed Standards, Final Report, January 2001; IBR approved for § 63.7491(g).

(3) EPA–454/B–08–002, Quality Assurance Handbook for Air Pollution Measurement Systems; Volume IV: Meteorological Measurements, Version 2.0 (Final), Issued March 2008; IBR approved for §§ 63.184(c); 63.7792(b).

(4) EPA–454/R–98–015, Office of Air Quality Planning and Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, September 1997; IBR approved for §§ 63.548(e); 63.864(e); 63.7525(j); 63.8450(e); 63.8600(e); 63.9632(a); 63.9804(f); 63.11224(f); 63.11423(e). (Available at: *https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000D5T6.pdf*).

(5) EPA–454/R–99–005, Office of Air Quality Planning and Standards (OAQPS), Meteorological Monitoring Guidance for Regulatory Modeling Applications, February 2000; IBR approved for appendix A to this part.

(6) EPA/600/R–12/531, EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, May 2012; IBR approved for § 63.2163(b).

(7) EPA–625/3–89–016, Interim Procedures for Estimating Risks Associated with Exposures to Mixtures of Chlorinated Dibenzo-p-Dioxins and –Dibenzofurans (CDDs and CDFs) and 1989 Update, March 1989; IBR approved for § 63.1513(d).

(8) EPA–821–R–02–019, Method 1631 Revision E, Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Absorption Fluorescence Spectrometry, Revision E, August 2002; IBR approved for table 6 to subpart DDDDD.

(9) EPA Method 200.8, Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma—Mass Spectrometry, Revision 5.4, 1994; IBR approved for table 6 to subpart DDDDD.

(10) In EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods (Available from: *www.epa.gov/hw-sw846/sw-846-compendium*):

(i) SW–846–0011, Sampling for Selected Aldehyde and Ketone Emissions from Stationary Sources, Revision 0, December 1996; IBR approved for table 4 to subpart DDDD.

(ii) SW–846–3020A, Acid Digestion of Aqueous Samples And Extracts For Total Metals For Analysis By GFAA Spectroscopy, Revision 1, July 1992; IBR approved for table 6 to subpart DDDDD; table 5 to subpart JJJJJJ.

(iii) SW–846–3050B, Acid Digestion of Sediments, Sludges, and Soils, Revision 2, December 1996; IBR approved for table 6 to subpart DDDDD; table 5 to subpart JJJJJJ.

(iv) SW–846–5030B, Purge-And-Trap For Aqueous Samples, Revision 2, December 1996; IBR approved for §§ 63.109(b), (c), (d), and (e); 63.509(b) and (c); 63.2492(b) and (c).

(v) SW–846–5031, Volatile, Nonpurgeable, Water-Soluble Compounds by Azeotropic Distillation, Revision 0, December 1996; IBR approved for §§ 63.109(b), (c), (d), and (e); 63.509(b) and (c); 63.2492(b) and (c).

(vi) SW–846–7470A, Mercury In Liquid Waste (Manual Cold-Vapor Technique), Revision 1, September 1994; IBR approved for table 6 to subpart DDDDD; table 5 to subpart JJJJJJ.

(vii) SW–846–7471B, Mercury In Solid Or Semisolid Waste (Manual Cold-Vapor Technique), Revision 2, February 2007; IBR approved for table 6 to subpart DDDDD; table 5 to subpart JJJJJJ.

(viii) SW–846–8015C, Nonhalogenated Organics by Gas Chromatography, Revision 3, February 2007; IBR approved for §§ 63.11960; 63.11980; table 10 to subpart HHHHHHH.

(ix) SW–846–8260B, Volatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS), Revision 2, December 1996; IBR approved for §§ 63.1107(a); 63.11960; 63.11980; table 10 to subpart HHHHHHH.

(x) SW–846–8260D, Volatile Organic Compounds By Gas Chromatography/Mass Spectrometry, Revision 4, June 2018; IBR approved for §§ 63.109(b), (c), (d), and (e); 63.509(b) and (c); 63.2492(b) and (c).

(xi) SW–846–8270D, Semivolatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS), Revision 4, February 2007; IBR approved for §§ 63.1107(a); 63.11960; 63.11980; table 10 to subpart HHHHHHH.

(xii) SW–846–8315A, Determination of Carbonyl Compounds by High Performance Liquid Chromatography (HPLC), Revision 1, December 1996; IBR approved for §§ 63.11960; 63.11980; table 10 to subpart HHHHHHH.

(xiii) SW–846–5050, Bomb Preparation Method for Solid Waste, Revision 0, September 1994; IBR approved for table 6 to subpart DDDDD.

(xiv) SW–846–6010C, Inductively Coupled Plasma-Atomic Emission Spectrometry, Revision 3, February 2007; IBR approved for table 6 to subpart DDDDD.

(xv) SW–846–6020A, Inductively Coupled Plasma-Mass Spectrometry, Revision 1, February 2007; IBR approved for table 6 to subpart DDDDD.

(xvi) SW–846–7060A, Arsenic (Atomic Absorption, Furnace Technique), Revision 1, September 1994; IBR approved for table 6 to subpart DDDDD.

(xvii) SW–846–7740, Selenium (Atomic Absorption, Furnace Technique), Revision 0, September 1986; IBR approved for table 6 to subpart DDDDD.

(xviii) SW–846–9056, Determination of Inorganic Anions by Ion Chromatography, Revision 1, February 2007; IBR approved for table 6 to subpart DDDDD.

(xix) SW–846–9076, Test Method for Total Chlorine in New and Used Petroleum Products by Oxidative Combustion and Microcoulometry, Revision 0, September 1994; IBR approved for table 6 to subpart DDDDD.

(xx) SW–846–9250, Chloride (Colorimetric, Automated Ferricyanide AAI), Revision 0, September 1986; IBR approved for table 6 to subpart DDDDD.

* * * * *

(u) Texas Commission on Environmental Quality (TCEQ) Library, Post Office Box 13087, Austin, Texas 78711–3087; phone: (512) 239–0028; email: *info@www.tceq.texas.gov*; website: *www.tceq.texas.gov.*

(1) ''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, January 31, 2003; IBR approved for §§ 63.104(f) and (g); 63.654(c) and (g); 63.655(i); 63.1086(e); 63.1089; 63.2490(d); 63.2525(r); 63.11920. (Available from: *www.tceq.texas.gov/downloads/compliance/investigations/assistance/samplingappp.pdf*).

(2) [Reserved]

■ 42. Revise the heading of subpart F to read as follows:

Subpart F—National Emission Standards for Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry

■ 43. Amend § 63.100 by:

■ a. Revising paragraphs (a), (e)(1) and (3), (f)(8) and (11), (j)(3), (k) introductory text, (k)(4) introductory text, (k)(5)(ii), and (k)(6)(i);

■ b. Adding paragraphs (k)(10) through (12);

■ c. Revising paragraphs (l)(1)(iii), (l)(4)(ii)(B), (m) introductory text, (q) introductory text, (q)(3), and (q)(4)(i) introductory text;

■ d. Adding paragraph (q)(4)(iii); and

■ e. Revising paragraph (q)(5).

The revisions and additions read as follows:

§ 63.100 Applicability and designation of source.

(a) This subpart provides applicability provisions, definitions, and other general provisions that are applicable to subparts G and H of this part. This subpart also provides requirements for certain heat exchange systems, maintenance wastewater, and flares.

* * * * *

(e) * * *

(1) This subpart applies to maintenance wastewater and heat exchange systems within a source that is subject to this subpart; and also applies to flares used to reduce organic HAP emissions from a source.

* * * * *

(3) This subpart and subpart H of this part apply to pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, instrumentation systems, surge control vessels, and bottoms receivers within a source that is subject to this subpart. Subpart H also contains fenceline monitoring requirements that apply to all emission sources (*i.e.,* maintenance wastewater, heat exchange systems, process vents, storage vessels, transfer racks, equipment identified in § 63.149, wastewater streams and associated treatment residuals within a source, and pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, instrumentation systems, surge control vessels, and bottoms receivers within a source). If specific items of equipment, comprising part of a chemical manufacturing process unit subject to this subpart, are managed by different administrative organizations (*e.g.,* different companies, affiliates, departments, divisions, etc.), those items of equipment may be aggregated with any chemical manufacturing process unit within the source for all purposes under subpart H, providing there is no delay in the applicable compliance date in § 63.100(k).

(f) * * *

(8) Except for storage vessels in ethylene oxide service, vessels storing organic liquids that contain organic hazardous air pollutants only as impurities;

* * * * *

(11) Equipment that is intended to operate in organic hazardous air pollutant service, as defined in § 63.101, for less than 300 hours during the calendar year.

* * * * *

(j) * * *

(3) Ethylene production units, regardless of whether the units supply feedstocks that include chemicals listed in table 1 of this subpart to chemical manufacturing process units that are subject to the provisions of subpart F, G, or H of this part.

* * * * *

(k) Except as provided in paragraphs (l), (m), and (p) of this section, sources subject to subpart F, G, or H of this part are required to achieve compliance on or before the dates specified in paragraphs (k)(1) through (8) and (10) and (11) of this section.

* * * * *

(4) Existing chemical manufacturing process units in Groups I and II as identified in table 1 of this subpart shall be in compliance with the requirements of § 63.164 no later than May 10, 1995, for any compressor meeting one or more of the criteria in paragraphs (k)(4)(i) through (iv) of this section, if the work can be accomplished without a process unit shutdown, as defined in § 63.101.

* * * * *

(5) * * *

(ii) The work can be accomplished without a process unit shutdown as defined in § 63.101;

* * * * *

(6)(i) If compliance with the compressor provisions of § 63.164 cannot reasonably be achieved without a process unit shutdown, as defined in § 63.101, the owner or operator shall achieve compliance no later than April 22, 1996, except as provided for in paragraph (k)(6)(ii) of this section. The owner or operator who elects to use this provision shall comply with the requirements of § 63.103(g).

* * * * *

(10) All affected sources that commenced construction or reconstruction on or before April 25, 2023, must be in compliance with the requirements listed in paragraphs (k)(10)(i) through (viii) of this section upon initial startup or on July 15, 2027, whichever is later. All affected sources that commenced construction or reconstruction after April 25, 2023, must be in compliance with the requirements listed in paragraphs (k)(10)(i) through (viii) of this section upon initial startup, or on July 15, 2024, whichever is later.

(i) The general requirements specified in paragraph (q)(4)(iii) of this section, §§ 63.102(e) and (f), 63.103(b)(1), (b)(3)(ii), and (c)(2)(iv), 63.107(j), 63.108, 63.110(h)(2) and (j)(1), and § 63.148(f)(4), (i)(3)(iii), and (j)(4).

(ii) For heat exchange systems, the requirements specified in § 63.104(a)(3) and (a)(4)(v) (g), (h), (i), (j), and (l).

(iii) For process vents, the requirements specified in §§ 63.113(a)(4) and (5), (k), and (l), 63.114(a)(5)(v) and (d)(3), 63.115(g), 63.116(g), 63.117(g), and 63.118(f)(7) and (n).

(iv) For storage vessels, the requirements specified in §§ 63.119(a)(6), 63.119(b)(5)(ix) through (xii), 63.119(b)(7), 63.119(f)(3)(iv), 63.120(d)(1)(iii), and footnotes b and c of tables 5 and 6 to subpart G of this part. For pressure vessels, the requirements specified in §§ 63.119(a)(7), 63.122(j), and 63.123(b).

(v) For transfer operations, the requirements specified in §§ 63.126(h)(1), 63.127(b)(4) and (d)(3), and 63.130(a)(2)(iv), (b)(3), and (d)(7).

(vi) For process wastewater, the requirements specified in §§ 63.132(a)(2)(i)(C) and (b)(3)(i)(C), 63.135(b)(4), 63.139(d)(5), and 63.145(a)(10).

(vii) For equipment leaks and pressure relief devices, the requirements specified in §§ 63.165(a) and (e), 63.170(b), 63.172(j)(4), 63.181(g)(3)(iii), and 63.182(d)(2)(xix).

(viii) The other notification, reports, and records requirements specified in § 63.152(c)(2)(ii)(F), table 3 to subpart G of this part, item 3 in column 3 for presence of flow and monthly inspections of sealed valves for all control devices, table 7 to subpart G of this part, item 3 in column 3 for presence of flow and monthly inspections of sealed valves for all control devices and vapor balancing systems, and table 20 to subpart G of this part, item (8)(iii).

(11) All affected sources that commenced construction or reconstruction on or before April 25, 2023, must be in compliance with the ethylene oxide requirements in §§ 63.104(k), 63.109, 63.113(j), 63.119(a)(5), 63.120(d)(9), 63.124, 63.163(a)(1)(iii), (b)(2)(iv), (c)(4), and (e)(7), 63.168(b)(2)(iv) and (d)(5), 63.171(f), and 63.174(a)(3), (b)(3)(vi), (b)(5), and (g)(3), upon initial startup or on July 15, 2026, whichever is later. All affected sources that commenced construction or reconstruction after April 25, 2023, must be in compliance with the ethylene oxide requirements listed in §§ 63.104(k), 63.109, 63.113(j), 63.119(a)(5), 63.120(d)(9), § 63.124, 63.163(a)(1)(iii), (b)(2)(iv), (c)(4), and (e)(7), 63.168(b)(2)(iv) and (d)(5), § 63.171(f), and 63.174(a)(3), (b)(3)(vi), (b)(5), and (g)(3), upon initial startup or on July 15, 2024, whichever is later.

(12) All affected sources that commenced construction or reconstruction on or before April 25, 2023, must commence fenceline monitoring according to the requirements in § 63.184 by no later than July 15, 2026, however requirements for corrective actions are not required until on or after July 15, 2027. All affected sources that commenced construction or reconstruction after April 25, 2023, must be in compliance with the fenceline monitoring requirements listed in § 63.184 upon initial startup, or on July 15, 2024, whichever is later.

(l) * * *

(1) * * *

(iii) The addition has the potential to emit 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP's, unless the Administrator establishes a lesser quantity.

* * * * *

(4) * * *

(ii) * * *

(B) If a deliberate operational process change to an existing chemical manufacturing process unit causes a Group 2 emission point to become a Group 1 emission point, if a surge control vessel or bottoms receiver becomes subject to § 63.170, or if a compressor becomes subject to § 63.164, the owner or operator shall be in compliance upon initial start-up or by 3 years after April 22, 1994, 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 (3) of this section to establish a compliance date.

* * * * *

(m) If a change that does not meet the criteria in paragraph (l)(4) of this section is made to a chemical manufacturing process unit subject to subparts F and G of this part, and the change causes a Group 2 emission point to become a Group 1 emission point (as defined in § 63.101), then the owner or operator shall comply with the requirements of subpart G of this part 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.

* * * * *

(q) If the owner or operator of a process vent, or of a gas stream transferred subject to § 63.113(i), is unable to comply with the provisions of §§ 63.113 through 63.118 by the applicable compliance date specified in paragraph (k), (l), or (m) of this section for the reasons stated in paragraph (q)(1), (3), or (5) of this section, the owner or operator shall comply with the applicable provisions in §§ 63.113 through 63.118 as expeditiously as practicable, but in no event later than the date approved by the Administrator pursuant to paragraph (q)(2), (4), or (6) of this section, respectively. For requests under paragraph (q)(1) or (3) of this section, the date approved by the Administrator may be earlier than, and shall not be later than, the later of January 22, 2004, or 3 years after the transferee's refusal to accept the stream for disposal. For requests submitted under paragraph (q)(5) of this section, the date approved by the Administrator may be earlier than, and shall not be later than, 3 years after the date of publication of the amendments to this subpart or to subpart G of this part which created the need for an extension of the compliance.

* * * * *

(3) Except as specified in paragraph (q)(4)(iii) of this section, if the owner or operator has been sending the gas stream for disposal as described in § 63.113(i) to a transferee who had submitted a written certification as described in § 63.113(i)(2), and the transferee revokes its written certification, the owner or operator shall comply with paragraphs (q)(4)(i) and (ii) of this section. During the period between the date when the owner or operator receives notice of revocation of the transferee's written certification and the compliance date established under paragraph (q)(4) of this section, the

owner or operator shall implement, to the extent reasonably available, measures to prevent or minimize excess emissions to the extent practical. For purposes of this paragraph (q)(3), the term ''excess emissions'' means emissions in excess of those that would have occurred if the transferee had continued managing the gas stream in compliance with the requirements in §§ 63.113 through 63.118. The measures to be taken shall be identified in the applicable startup, shutdown, and malfunction plan. If the measures that can be reasonably taken will change over time, so that a more effective measure which could not reasonably be taken initially would be reasonable at a later date, the Administrator may require the more effective measure by a specified date (in addition to or instead of any other measures taken sooner or later than that date) as a condition of approval of the compliance schedule.

(4) * * *

(i) An owner or operator directed to comply with this paragraph (q)(4) shall submit to the Administrator for approval the documents specified in paragraphs (q)(4)(i)(A) through (E) of this section no later than 90 days after the owner or operator receives notice of revocation of the transferee's written certification.

* * * * *

(iii) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), paragraph (q)(3) of this section no longer applies.

(5) If the owner's or operator's inability to meet otherwise applicable compliance deadlines is due to amendments of this subpart or of subpart G of this part published on or after January 22, 2001, and neither condition specified in paragraph (q)(1) or (3) of this section is applicable, the owner or operator shall comply with paragraph (q)(6) of this section.

* * * * *

■ 44. Amend § 63.101 by revising paragraph (b) to read as follows:

§ 63.101 Definitions.

* * * * *

(b) All other terms used in this subpart and subparts G and H of this part shall have the meaning given them in the Act and in this section. 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 subparts F, G, and H of this part.

Air oxidation reactor means a device or vessel in which air, or a combination of air and oxygen, is used as an oxygen source in combination with one or more organic reactants to produce one or more organic compounds. Air oxidation reactor includes the product separator and any associated vacuum pump or steam jet.

Ancillary activities means boilers and incinerators (not used to comply with the emission limits of subparts F, G, and H of this part), chillers and refrigeration systems, and other equipment and activities that are not directly involved (*i.e.,* they operate within a closed system and materials are not combined with process fluids) in the processing of raw materials or the manufacturing of a product or isolated intermediate.

Annual average concentration, as used in the wastewater provisions, means the flow-weighted annual average concentration, as determined according to the procedures specified in § 63.144(b).

Annual average flow rate, as used in the wastewater provisions, means the annual average flow rate, as determined according to the procedures specified in § 63.144(c).

Automated monitoring and recording system means any means of measuring values of monitored parameters and creating a hard copy or computer record of the measured values that does not require manual reading of monitoring instruments and manual transcription of data values. Automated monitoring and recording systems include, but are not limited to, computerized systems and strip charts.

Batch operation means a noncontinuous operation in which a discrete quantity or batch of feed is charged into a unit operation within a chemical manufacturing process unit and processed at one time. Batch operation includes noncontinuous operations in which the equipment is fed intermittently or discontinuously. Addition of raw material and withdrawal of product do not occur simultaneously in a batch operation. After each batch operation, the equipment is generally emptied before a fresh batch is started.

Batch process means a process in which the equipment is fed intermittently or discontinuously. Processing then occurs in this equipment after which the equipment is generally emptied. Examples of industries that use batch processes include pharmaceutical production and pesticide production.

Batch process vent means gaseous venting to the atmosphere from a batch operation.

Batch product-process equipment train means the collection of equipment (*e.g.,* connectors, reactors, valves, pumps, etc.) configured to produce a specific product or intermediate by a batch process.

Bench-scale batch process means a batch process (other than a research and development facility) that is operated on a small scale, such as one capable of being located on a laboratory bench top. This bench-scale equipment will typically include reagent feed vessels, a small reactor and associated product separator, recovery and holding equipment. These processes are only capable of producing small quantities of product.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator. Boiler also means any industrial furnace as defined in 40 CFR 260.10.

Bottoms receiver means a tank that collects distillation bottoms before the stream is sent for storage or for further downstream processing.

Breakthrough means the time when the level of HAP or TOC, measured at the outlet of the first bed, has been detected is at the highest concentration allowed to be discharged from the adsorber system and indicates that the adsorber bed should be replaced.

By compound means by individual stream components, not carbon equivalents.

By-product means a chemical that is produced coincidentally during the production of another chemical.

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 process unit or CMPU means the equipment assembled and connected by pipes or ducts to process raw materials and to manufacture an intended product. A chemical manufacturing process unit consists of more than one unit operation. For the purpose of this subpart, chemical manufacturing process unit includes air oxidation reactors and their associated product separators and recovery devices; reactors and their associated product separators and recovery devices; distillation units and their associated distillate receivers and recovery devices; associated unit operations; associated recovery devices; and any feed, intermediate and product storage vessels and pressure vessels, product transfer racks, and connected ducts and piping. A chemical manufacturing process unit includes pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, instrumentation systems, and control devices or systems. A chemical manufacturing process unit is identified by its primary product. Ancillary activities are not considered a process or part of any process. Quality assurance/quality control laboratories are not considered part of any process.

Closed biological treatment process means a tank or surface impoundment where biological treatment occurs and air emissions from the treatment process are routed to either a control device by means of a closed vent system or to a fuel gas system by means of hard-piping. The tank or surface impoundment has a fixed roof, as defined in this section, or a floating flexible membrane cover that meets the requirements specified in § 63.134.

Closed-loop system means an enclosed system that returns process fluid to the process and is not vented to the atmosphere except through a closed-vent system.

Closed-purge system means a system or combination of system and portable containers, to capture purged liquids. Containers must be covered or closed when not being filled or emptied.

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 point to a control device.

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 emissions.

Compliance date means the dates specified in § 63.100(k) or (l)(3) for process units subject to subpart F of this part; the dates specified in § 63.190(e) for process units subject to subpart I of this part. For sources subject to other subparts in this part that reference this subpart, compliance date will be defined in those subparts. However, the compliance date for § 63.170 shall be no later than 3 years after the effective date of those subparts unless otherwise specified in such other subparts.

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 not inaccessible, glass, or glass-lined as described in § 63.174(h).

Container, as used in the wastewater provisions, means any portable waste management unit that has a capacity greater than or equal to 0.1 m^3 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.

Continuous record means documentation, either in hard copy or computer readable form, of data values measured at least once every 15 minutes and recorded at the frequency specified in § 63.152(f) or (g).

Continuous recorder means a data recording device that either records an instantaneous data value at least once every 15 minutes or records 15-minute or more frequent block average values.

Continuous seal means a seal that forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the floating roof. A continuous seal may be a vapor-mounted, liquid-mounted, or metallic shoe seal. A continuous seal may be constructed of fastened segments so as to form a continuous seal.

Continuous vapor processing system means a vapor processing system that treats total organic compound vapors collected from tank trucks or railcars on a demand basis without intermediate accumulation in a vapor holder.

Control device means any combustion device, recovery device, or recapture device. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, incinerators, flares, boilers, and process heaters. For process vents, recapture devices are considered control devices but recovery devices are not considered control devices, and for a steam stripper, a primary condenser is not considered a control device.

Co-product means a chemical that is produced during the production of another chemical.

Cover, as used in the wastewater provisions, means a device or system which is placed on or over a waste management unit containing wastewater or residuals so that the entire surface area is enclosed 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 when not in use. Examples of covers include a fixed roof installed on a wastewater tank, a lid installed on a container, and an air-supported enclosure installed over a waste management unit.

Dioxins and furans means total tetra-through octachlorinated dibenzo-p-dioxins and dibenzofurans.

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.

Double block and bleed system means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

Duct work means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screws or crimping. Hard-piping is not ductwork.

Emission point means an individual process vent, storage vessel, transfer rack, wastewater stream, or equipment leak.

Empty or emptying means the removal of the stored liquid from a storage vessel. Storage vessels where stored liquid is left on the walls, as bottom clingage, or in pools due to bottom irregularities are considered empty. Lowering of the stored liquid level, so that the floating roof is resting on its legs, as necessitated by normal vessel operation (for example, when changing stored material or when transferring material out of the vessel for shipment) is not considered emptying.

Enhanced biological treatment system or enhanced biological treatment process means an aerated, thoroughly mixed treatment unit(s) that contains biomass suspended in water followed by a clarifier that removes biomass from the treated water and recycles recovered biomass to the aeration unit. The mixed liquor volatile suspended solids (biomass) is greater than 1 kilogram per cubic meter throughout each aeration unit. The biomass is suspended and aerated in the water of the aeration unit(s) by either submerged air flow or mechanical agitation. A thoroughly mixed treatment unit is a unit that is designed and operated to approach or achieve uniform biomass distribution and organic compound concentration throughout the aeration unit by quickly dispersing the recycled biomass and the wastewater entering the unit.

Equipment leak means emissions of organic hazardous air pollutants from a connector, pump, compressor, agitator, pressure relief device, sampling connection system, open-ended valve or line, valve, surge control vessel, bottoms receiver, or instrumentation system in organic hazardous air pollutant service as defined in this section.

Equipment means each pump, compressor, agitator, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, surge control vessel, bottoms receiver, and instrumentation system in organic hazardous air pollutant service; and any control devices or systems required by this subpart.

Ethylene production unit means a chemical manufacturing process unit in which ethylene and/or propylene are produced by separation from petroleum refining process streams or by subjecting hydrocarbons to high temperatures in the presence of steam. The ethylene process unit includes the separation of ethylene and/or propylene from associated streams such as a C_4 product, pyrolysis gasoline, and pyrolysis fuel oil. The ethylene process does not include the manufacture of SOCMI chemicals such as the production of butadiene from the C_4 stream and aromatics from pyrolysis gasoline.

External floating roof means a pontoon-type or double-deck-type cover that rests on the liquid surface in a storage vessel or waste management unit with no fixed roof.

Fill or *filling* means the introduction of organic hazardous air pollutant into a storage vessel or the introduction of a wastewater stream or residual into a waste management unit, but not necessarily to complete capacity.

First attempt at repair means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere, followed by monitoring as specified in § 63.180(b) and (c), as appropriate, to verify whether the leak is repaired, unless the owner or operator determines by other means that the leak is not repaired.

Fixed roof means a cover that is mounted on a waste management unit or storage vessel in a stationary manner and that does not move with fluctuations in liquid level.

Flame zone means the portion of the combustion chamber in a boiler or process heater occupied by the flame envelope.

Flexible operation unit means a chemical manufacturing process unit that manufactures different chemical products periodically by alternating raw materials or operating conditions. These units are also referred to as campaign plants or blocked operations.

Floating roof means a cover 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 waste management unit or storage vessel wall.

Flow indicator means a device which indicates whether gas flow is, or whether the valve position would allow gas flow to be, present in a line.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in in-process combustion equipment such as furnaces and gas turbines either singly or in combination.

Group 1 process vent means, before July 15, 2027, a process vent for which the vent stream flow rate is greater than or equal to 0.005 standard cubic meter per minute, the total organic HAP concentration is greater than or equal to 50 parts per million by volume, and the total resource effectiveness index value, calculated according to § 63.115, is less than or equal to 1.0. On and after July 15, 2027, Group 1 process vent means a process vent that emits greater than or equal to 1.0 pound per hour of total organic HAP.

Group 1 storage vessel means a storage vessel that meets the criteria for design storage capacity and stored-liquid maximum true vapor pressure specified in table 5 to subpart G of this part for storage vessels at existing sources, and in table 6 to subpart G of this part for storage vessels at new sources.

Group 1 transfer rack means a transfer rack that annually loads greater than or equal to 0.65 million liter of liquid products that contain organic hazardous air pollutants with a rack weighted average vapor pressure greater than or equal to 10.3 kilopascals.

Group 1 wastewater stream means a wastewater stream consisting of process wastewater as defined in this section at an existing or new source that meets the criteria for Group 1 status in § 63.132(c) for table 9 compounds and/or a wastewater stream consisting of process wastewater at a new source that meets the criteria for Group 1 status in § 63.132(d) for table 8 compounds.

Group 2 process vent means, before July 15, 2027, a process vent for which the vent stream flow rate is less than 0.005 standard cubic meter per minute, the total organic HAP concentration is less than 50 parts per million by volume or the total resource effectiveness index value, calculated according to § 63.115, is greater than 1.0. On and after July 15, 2027, Group 2 process vent means a process vent that emits less than 1.0 pound per hour of total organic HAP.

Group 2 storage vessel means a storage vessel that does not meet the definition of a Group 1 storage vessel.

Group 2 transfer rack means a transfer rack that does not meet the definition of Group 1 transfer rack.

Group 2 wastewater stream means any process wastewater stream that does not meet the definition of a Group 1 wastewater stream.

Halogenated vent stream or *halogenated stream* means a vent stream from a process vent or transfer operation determined to have a mass emission rate of halogen atoms contained in organic compounds of 0.45 kilograms per hour or greater determined by the procedures presented in § 63.115(d)(2)(v).

Halogens and *hydrogen halides* means hydrogen chloride (HCl), chlorine (Cl_2), hydrogen bromide (HBr), bromine (Br_2), and hydrogen fluoride (HF).

Hard-piping means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as American National Standards Institute (ANSI) B31–3 (see § 63.14 for ANSI contact information).

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 CMPU 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 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 CMPU 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.

Impurity means a substance that is produced coincidentally with the primary product or is present in a raw material. An impurity does not serve a useful purpose in the production or use of the primary product and is not isolated.

In ethylene oxide service means the following:

(i) For equipment leaks, any equipment that contains or contacts a fluid (liquid or gas) that is at least 0.1 percent by weight of ethylene oxide. If information exists that suggests ethylene oxide could be present in equipment, the equipment is considered to be ''in ethylene oxide service'' unless the procedures specified in § 63.109 are performed to demonstrate that the equipment does not meet the definition of being ''in ethylene oxide service''. Examples of information that could suggest ethylene oxide could be present in equipment, include calculations based on safety data sheets, material balances, process stoichiometry, or previous test results provided the results are still relevant to the current operating conditions.

(ii) For heat exchange systems, any heat exchange system in a process that cools process fluids (liquid or gas) that are 0.1 percent or greater by weight of ethylene oxide. If knowledge exists that suggests ethylene oxide could be present in a heat exchange system, then the heat exchange system is considered to be ''in ethylene oxide service'' unless the procedures specified in § 63.109 are performed to demonstrate that the heat exchange system does not meet the definition of being ''in ethylene oxide service''. Examples of information that could suggest ethylene oxide could be present in a heat exchange system, include calculations based on safety data sheets, material balances, process stoichiometry, or previous test results provided the results are still relevant to the current operating conditions.

(iii) For process vents, each Group 1 and Group 2 process vent in a process that, when uncontrolled, contains a concentration of greater than or equal to 1 ppmv undiluted ethylene oxide, and when combined, the sum of all these process vents within the process would emit uncontrolled, ethylene oxide emissions greater than or equal to 5 lb/yr (2.27 kg/yr). If information exists that suggests ethylene oxide could be present in a Group 1 or Group 2 process vent, then the Group 1 or Group 2 process vent is considered to be ''in ethylene oxide service'' unless an analysis is performed as specified in § 63.109 to demonstrate that the Group 1 or Group 2 process vent does not meet the definition of being ''in ethylene oxide service''. Examples of information that could suggest ethylene oxide could be present in a Group 1 or Group 2 process vent, include calculations based on safety data sheets, material balances, process stoichiometry, or previous test results provided the results are still relevant to the current operating conditions.

(iv) For storage vessels, storage vessels of any capacity and vapor pressure storing a liquid that is at least 0.1 percent by weight of ethylene oxide. If knowledge exists that suggests ethylene oxide could be present in a storage vessel, then the storage vessel is considered to be ''in ethylene oxide service'' unless the procedures specified in § 63.109 are performed to demonstrate that the storage vessel does not meet the definition of being ''in ethylene oxide service''. The exemption for ''vessels storing organic liquids that contain organic hazardous air pollutants only as impurities'' listed in the definition of ''storage vessel'' in this section does not apply for storage vessels that may be in ethylene oxide service. Examples of information that could suggest ethylene oxide could be present in a storage vessel, include calculations based on safety data sheets, material balances, process stoichiometry, or previous test results provided the results are still relevant to the current operating conditions.

(v) For wastewater streams, any wastewater stream that contains total annual average concentration of ethylene oxide greater than or equal to 1 parts per million by weight at any flow rate. If knowledge exists that suggests ethylene oxide could be present in a wastewater stream, then the wastewater stream is considered to be ''in ethylene oxide service'' unless sampling and analysis is performed as specified in § 63.109 to demonstrate that the wastewater stream does not meet the definition of being ''in ethylene oxide service''. Examples of information that could suggest ethylene oxide could be present in a wastewater stream, include calculations based on safety data sheets, material balances, process stoichiometry, or previous test results provided the results are still relevant to the current operating conditions.

In food/medical service means that a piece of equipment in organic hazardous air pollutant service contacts a process stream used to manufacture a Food and Drug Administration regulated product where leakage of a barrier fluid into the process stream would cause any of the following:

(i) A dilution of product quality so that the product would not meet written specifications,

(ii) An exothermic reaction which is a safety hazard,

(iii) The intended reaction to be slowed down or stopped, or

(iv) An undesired side reaction to occur.

In gas/vapor service means that a piece of equipment in organic hazardous air pollutant service contains a gas or vapor at operating conditions.

In heavy liquid service means that a piece of equipment in organic hazardous air pollutant service is not in gas/vapor service or in light liquid service.

In light liquid service means that a piece of equipment in organic hazardous air pollutant service contains a liquid that meets the following conditions:

(i) The vapor pressure of one or more of the organic compounds is greater than 0.3 kilopascals at 20 °C,

(ii) The total concentration of the pure organic compounds constituents having a vapor pressure greater than 0.3 kilopascals at 20 °C is equal to or greater than 20 percent by weight of the total process stream, and

(iii) The fluid is a liquid at operating conditions.

Note 1 to *In light liquid service:* Vapor pressures may be determined by the methods described in § 60.485(e)(1) of this chapter.

In liquid service means that a piece of equipment in organic hazardous air pollutant service is not in gas/vapor service.

In organic hazardous air pollutant or *in organic HAP service* means that a piece of equipment or heat exchange system either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP's as determined according to the provisions of § 63.180(d). The provisions of § 63.180(d) also specify how to determine that a piece of equipment is not in organic HAP service. For purposes of the definition of ''heat exchange system'', the term ''equipment'' in § 63.180(d) includes heat exchange systems.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals below ambient pressure.

In volatile organic compound or *in VOC service* means, for the purposes of subpart H of this part, that:

(i) The piece of equipment contains or contacts a process fluid that is at least

10 percent VOC by weight (see § 60.2 of this chapter for the definition of VOC, and § 60.485(d) of this chapter to determine whether a piece of equipment is not in VOC service); and

(ii) The piece of equipment is not in heavy liquid service as defined in § 60.481 of this chapter.

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. The above energy recovery section limitation does not apply to an energy recovery section used solely to preheat the incoming vent stream or combustion air.

Individual drain system means the stationary system used to convey wastewater streams or residuals to a waste management unit or to discharge or disposal. The term includes hard-piping, all process drains and junction boxes, together with their associated sewer lines and other junction boxes, manholes, sumps, and lift stations, conveying wastewater streams or residuals. A segregated stormwater sewer system, which is 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, is excluded from this definition.

Initial start-up means the first time a new or reconstructed source begins production, or, for equipment added or changed as described in § 63.100(l) or (m), the first time the equipment is put into operation. Initial start-up does not include operation solely for testing equipment. For purposes of subpart G of this part, initial start-up does not include subsequent start-ups (as defined in this section) of chemical manufacturing process units following malfunctions or shutdowns or following changes in product for flexible operation units or following recharging of equipment in batch operation. For purposes of subpart H of this part, initial start-up does not include subsequent start-ups (as defined in this section) of process units (as defined in § this section) following malfunctions or process unit shutdowns.

In-situ sampling systems means nonextractive samplers or in-line samplers.

Instrumentation system means a group of equipment components used to condition and convey a sample of the process fluid to analyzers and instruments for the purpose of determining process operating conditions (*e.g.,* composition, pressure, flow, etc.). Valves and connectors are the predominant type of equipment used in instrumentation systems; however, other types of equipment may also be included in these systems. Only valves nominally 0.5 inches and smaller, and connectors nominally 0.75 inches and smaller in diameter are considered instrumentation systems for the purposes of subpart H of this part. Valves greater than nominally 0.5 inches and connectors greater than nominally 0.75 inches associated with instrumentation systems are not considered part of instrumentation systems and must be monitored individually.

Intermittent vapor processing system means a vapor processing system that employs an intermediate vapor holder to accumulate total organic compound vapors collected from tank trucks or railcars, and treats the accumulated vapors only during automatically controlled cycles.

Internal floating roof means a cover that rests or floats on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel or waste management unit that has a permanently affixed roof.

Junction box means a manhole or access point to a wastewater sewer line or a lift station.

Liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel or waste management unit and the floating roof. The seal is mounted continuously around the circumference of the vessel or unit.

Liquids dripping means any visible leakage from the seal including dripping, spraying, misting, clouding, and ice formation. Indications of liquid dripping include puddling or new stains that are indicative of an existing evaporated drip.

Loading cycle means the time period from the beginning of filling a tank truck or railcar until flow to the control device ceases, as measured by the flow indicator.

Loading rack means a single system used to fill tank trucks and railcars at a single geographic site. Loading equipment and operations that are physically separate (i.e., do not share common piping, valves, and other equipment) are considered to be separate loading racks.

Maintenance wastewater means wastewater generated by the draining of process fluid from components in the chemical manufacturing process unit into an individual drain system prior to or during maintenance activities. Maintenance wastewater can be generated during planned and unplanned shutdowns and during periods not associated with a shutdown. Examples of activities that can generate maintenance wastewaters include descaling of heat exchanger tubing bundles, cleaning of distillation column traps, draining of low legs and high point bleeds, draining of pumps into an individual drain system, and draining of portions of the chemical manufacturing process unit for repair.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the total organic HAP's in the stored or transferred liquid at the temperature equal to the highest calendar-month average of the liquid storage or transfer temperature for liquids stored or transferred above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for liquids stored or transferred at the ambient temperature, as determined:

(i) In accordance with methods described in API MPMS 19.2 (incorporated by reference as specified in § 63.14); or

(ii) As obtained from standard reference texts; or

(iii) As determined by the ASTM D2879–23 (incorporated by reference as specified in § 63.14); or

(iv) Any other method approved by the Administrator.

Metallic shoe seal or *mechanical shoe seal* means metal sheets that are held vertically against the wall of the storage vessel by springs, weighted levers, or other mechanisms and connected to the floating roof by braces or other means. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

Non-automated monitoring and recording system means manual reading of values measured by monitoring instruments and manual transcription of those values to create a record. Non-automated systems do not include strip charts.

Nonrepairable means that it is technically infeasible to repair a piece of equipment from which a leak has been detected without a process unit shutdown.

Oil-water separator or *organic-water separator* means a waste management unit, generally a tank used to separate oil or organics from water. An oil-water or organic-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 or organic-water separator include, but are not limited to, an American Petroleum Institute separator, parallel-plate interceptor, and corrugated-plate interceptor with the associated ancillary equipment.

On-site or *On site* means, with respect to records required to be maintained by this subpart, that the records are stored at a location within a major source which encompasses the affected source. On-site includes, but is not limited to, storage at the chemical manufacturing process unit to which the records pertain, or storage in central files elsewhere at the major source.

Open biological treatment process means a biological treatment process that is not a closed biological treatment process as defined in this section.

Open-ended valve or line means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

Operating permit means a permit required by 40 CFR part 70 or 71.

Organic hazardous air pollutant or *organic HAP* means one of the chemicals listed in table 2 of this subpart.

Organic monitoring device means a unit of equipment used to indicate the concentration level of organic compounds exiting a recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity.

Petroleum refining process, also referred to as a *petroleum refining process unit,* means a process that for the purpose of producing transportation fuels (such as gasoline and diesel fuels), heating fuels (such as fuel gas, distillate, and residual fuel oils), or lubricants separates petroleum or separates, cracks, or reforms unfinished derivatives. Examples of such units include, but are not limited to, alkylation units, catalytic hydrotreating, catalytic hydrorefining, catalytic hydrocracking, catalytic reforming, catalytic cracking, crude distillation, and thermal processes.

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.

Point of determination means each point where process wastewater exits the chemical manufacturing process unit. This subpart and subpart G of this part allows point of determination of the characteristics of a wastewater stream:

(i) At the point of determination or

(ii) Downstream of the point of determination if corrections are made for changes in flow rate and annual average concentration of table 8 or table 9 compounds as determined in § 63.144. Such changes include losses by air emissions; reduction of annual average concentration or changes in flow rate by mixing with other water or wastewater streams; and reduction in flow rate or annual average concentration by treating or otherwise handling the wastewater stream to remove or destroy hazardous air pollutants.

Point of transfer means:

(i) If the transfer is to an off-site location for control, the point where the conveyance crosses the property line; or

(ii) If the transfer is to an on-site location not owned or operated by the owner or operator of the source, the point where the conveyance enters the operation or equipment of the transferee.

Polymerizing monomer means a molecule or compound usually containing carbon and of relatively low molecular weight and simple structure (*e.g.,* hydrogen cyanide, acrylonitrile, styrene), which is capable of conversion to polymers, synthetic resins, or elastomers by combination with itself due to heat generation caused by a pump mechanical seal surface, contamination by a seal fluid (*e.g.,* organic peroxides or chemicals that will form organic peroxides), or a combination of both with the resultant polymer buildup causing rapid mechanical seal failure.

Pressure release means the emission of materials resulting from the system pressure being greater than the set pressure of the pressure relief device. This release can be one release or a series of releases over a short time period.

Pressure relief device or valve means a valve, rupture disk, or similar device used only to release an unplanned, nonroutine discharge of gas from process equipment in order to avoid safety hazards or equipment damage. A pressure relief device discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause. Such devices include conventional, spring-actuated relief valves, balanced bellows relief valves, pilot-operated relief valves, rupture disks, and breaking, buckling, or shearing pin devices. Devices that are actuated either by a pressure of less than or equal to 2.5 pounds per square inch gauge or by a vacuum are not pressure relief devices.

Pressure-assisted multi-point flare means a flare system consisting of multiple flare burners in staged arrays whereby the vent stream pressure is used to promote mixing and smokeless operation at the flare burner tips. Pressure-assisted multi-point flares are designed for smokeless operation at velocities up to Mach = 1 conditions (*i.e.,* sonic conditions), can be elevated or at ground level, and typically use cross-lighting for flame propagation to combust any flare vent gases sent to a particular stage of flare burners.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Primary fuel means the fuel that provides the principal heat input to the device. To be considered primary, the fuel must be able 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 a chemical manufacturing process unit as defined in subpart F of this part, a process subject to the provisions of subpart I of this part, or a process subject to another subpart in this part that references this subpart.

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 effected. 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 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, and would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown, is not a process unit shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not process unit shutdowns.

Process vent means the point of discharge to the atmosphere (or the point of entry into a control device, if any) of a gas stream if the gas stream has the characteristics specified in § 63.107(b) through (h), or meets the criteria specified in § 63.107(i). For purposes of §§ 63.113 through 63.118, all references to the characteristics of a process vent (*e.g.,* flow rate, total HAP concentration, or TRE index value) shall mean the characteristics of the gas stream.

Process wastewater means wastewater which, during manufacturing or processing, comes into direct contact with or results from the production or use of any raw material, intermediate product, finished product, by-product, or waste product. Examples are product tank drawdown or 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.

Process wastewater stream means a stream that contains process wastewater.

Product means a compound or chemical which is manufactured as the intended product of the chemical manufacturing process unit. By-products, isolated intermediates, impurities, wastes, and trace contaminants are not considered products.

Product separator means phase separators, flash drums, knock-out drums, decanters, degassers, and condenser(s) including ejector-condenser(s) associated with a reactor or an air oxidation reactor.

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.

Product tank, as used in the wastewater provisions, 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. This term has the same meaning as a product storage vessel.

Rack-weighted average partial pressure means the throughput weighted average of the average maximum true vapor pressure of liquids containing organic HAP transferred at a transfer rack. The rack-weighted average partial pressure shall be calculated using the equation below:

Equation 1 to Paragraph (b) Rack-Weighted Average Partial Pressure

$$P = \frac{\sum P_i G_i}{\sum G_i}$$

Where:

P = Rack-weighted average partial pressure, kilopascals.

P_i = Individual HAP maximum true vapor pressure, kilopascals, = X_i*P, where X_i is the mole fraction of compound i in the liquid.

G_i = Yearly volume of each liquid that contains organic HAP that is transferred at the rack, liters.

I = Each liquid that contains HAP that is transferred at the rack.

Reactor means a device or vessel 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. Reactor includes the product separator and any associated vacuum pump or steam jet.

Recapture device means an individual unit of equipment capable of and used for the purpose of recovering chemicals, but not normally for use, reuse, or sale. For example, a recapture device may recover chemicals primarily for disposal. Recapture devices include, but are not limited to, absorbers, carbon adsorbers, and condensers.

Recovery device means an individual unit of equipment capable of and normally used for the purpose of recovering chemicals for fuel value (*i.e.,* net positive heating value), use, reuse or for sale for fuel value, use, or reuse. Examples of equipment that may be recovery devices include absorbers, carbon adsorbers, condensers, oil-water separators or organic-water separators, or organic removal devices such as decanters, strippers, or thin-film evaporation units. For purposes of the monitoring, recordkeeping, and reporting requirements of subparts G and H of this part, recapture devices are considered recovery devices.

Reference control technology for process vents means a combustion device or recapture device used to reduce organic hazardous air pollutant emissions by 98 percent, or to an outlet concentration of 20 parts per million by volume.

Reference control technology for storage vessels means an internal floating roof meeting the specifications of § 63.119(b), an external floating roof meeting the specifications of § 63.119(c), an external floating roof converted to an internal floating roof meeting the specifications of § 63.119(d), or a closed-vent system to a control device achieving 95-percent reduction in organic HAP emissions. For purposes of emissions averaging, these four technologies are considered equivalent.

Reference control technology for transfer racks means a combustion device, recapture device, or recovery device used to reduce organic hazardous air pollutants emissions by 98 percent, or to an outlet concentration of 20 parts per million by volume; or a vapor balancing system.

Reference control technology for wastewater means the use of:

(i) Controls specified in §§ 63.133 through 63.137;

(ii) A steam stripper meeting the specifications of § 63.138(d) or any of the other alternative control measures specified in § 63.138(b), (c), (e), (f), (g), or (h); and

(iii) A control device to reduce by 95 percent (or to an outlet concentration of 20 parts per million by volume for combustion devices or for noncombustion devices controlling air emissions from waste management units other than surface impoundments or containers) the organic hazardous air pollutants emissions in the vapor streams vented from wastewater tanks, oil-water separators, containers, surface impoundments, individual drain systems, and treatment processes (including the design steam stripper) managing wastewater.

Relief valve means a type of pressure relief device that is designed to re-close after the pressure relief.

Repaired means that equipment:

(i) Is adjusted, or otherwise altered, to eliminate a leak as defined in the applicable sections of subpart H of this part, and

(ii) Unless otherwise specified in applicable provisions of subpart H of this part, is monitored as specified in § 63.180(b) and (c), as appropriate, to verify that emissions from the equipment are below the applicable leak definition.

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.

Residual means any liquid or solid material containing table 9 compounds that is removed from a wastewater stream by a waste management unit or treatment process that does not destroy organics (nondestructive unit). Examples of residuals from nondestructive wastewater management units are: the organic layer and bottom residue removed by a decanter or organic-water separator and the overheads from a steam stripper or air stripper. Examples of materials which are not residuals are: silt; mud; leaves; bottoms from a steam stripper or air stripper; and sludges, ash, or other materials removed from wastewater being treated by destructive devices such as biological treatment units and incinerators.

Routed to a process or route to a process means the emissions are conveyed to any enclosed portion of a process unit where the emissions are predominately recycled and/or consumed in the same manner as a material that fulfills the same function in the process; and/or transformed by chemical reaction into materials that are not organic hazardous air pollutants; and/or incorporated into a product; and/or recovered.

Sampling connection system means an assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take non-routine grab samples is not considered a sampling connection system.

Screwed connector means a threaded pipe fitting where the threads are cut on the pipe wall and the fitting requires only two pieces to make the connection (*i.e.,* the pipe and the fitting).

Secondary fuel means a fuel fired through a burner other than the primary fuel burner that provides supplementary heat in addition to the heat provided by the primary fuel.

Sensor means a device that measures a physical quantity or the change in a physical quantity, such as temperature, pressure, flow rate, pH, or liquid level.

Set pressure means the pressure at which a properly operating pressure relief device begins to open to relieve atypical process system operating pressure.

Sewer line means a lateral, trunk line, branch line, or other conduit including, but not limited to, grates, trenches, etc., used to convey wastewater streams or residuals to a downstream waste management unit.

Shutdown means for purposes including, but not limited to, periodic maintenance, replacement of equipment, or repair, the cessation of operation of a chemical manufacturing process unit or a reactor, air oxidation reactor, distillation unit, waste management unit, equipment required or used to comply with this subpart, subpart G or H of this part, or the emptying and degassing of a storage vessel. Shutdown does not include the routine rinsing or washing of equipment in batch operation between batches.

Simultaneous loading means, for a shared control device, loading of organic HAP materials from more than one transfer arm at the same time such that the beginning and ending times of loading cycles coincide or overlap and there is no interruption in vapor flow to the shared control device.

Single-seal system means a floating roof having one continuous seal that completely covers the space between the wall of the storage vessel and the edge of the floating roof. This seal may be a vapor-mounted, liquid-mounted, or metallic shoe seal.

Source means the collection of emission points to which this subpart applies as determined by the criteria in § 63.100. For purposes of subparts F, G, and H of this part, the term *affected source* as used in subpart A of this part has the same meaning as the term *source* defined here.

Specific gravity monitoring device means a unit of equipment used to monitor specific gravity and having a minimum accuracy of ±0.02 specific gravity units.

Start-up means the setting into operation of a chemical manufacturing process unit or a reactor, air oxidation reactor, distillation unit, waste management unit, or equipment required or used to comply with this subpart, subpart G or H of this part, or a storage vessel after emptying and degassing. Start-up includes initial start-up, operation solely for testing equipment, the recharging of equipment in batch operation, and transitional conditions due to changes in product for flexible operation units.

Start-up, shutdown, and malfunction plan means the plan required under § 63.6(e)(3). This plan details the procedures for operation and maintenance of the source during periods of start-up, shutdown, and malfunction. For each source as defined in this section, this definition no longer applies on and after July 15, 2027.

Steam jet ejector means a steam nozzle which discharges a high-velocity jet across a suction chamber that is connected to the equipment to be evacuated.

Storage vessel means a tank or other vessel that is used to store organic liquids that contain one or more of the organic HAP's listed in table 2 to this subpart and that has been assigned, according to the procedures in § 63.100(g), to a chemical manufacturing process unit that is subject to this subpart. Storage vessel does not include:

(i) Vessels permanently attached to motor vehicles such as trucks, railcars, barges, or ships;

(ii) Vessels with capacities smaller than 38 cubic meters;

(iii) Except for storage vessels in ethylene oxide service, vessels storing organic liquids that contain organic hazardous air pollutants only as impurities;

(iv) Bottoms receiver tanks;

(v) Surge control vessels; or

(vi) Wastewater storage tanks. Wastewater storage tanks are covered under the wastewater provisions.

Surface impoundment means a waste management unit which is a natural topographic depression, manmade excavation, or diked area formed primarily of earthen materials (although it may be lined with manmade materials), which is designed to hold an accumulation of liquid wastes or waste containing free liquids. A surface impoundment is used for the purpose of treating, storing, or disposing of wastewater or residuals, and is not an injection well. Examples of surface impoundments are equalization, settling, and aeration pits, ponds, and lagoons.

Surge control vessel means feed drums, recycle drums, and intermediate vessels. Surge control vessels are used within a chemical manufacturing process unit when in-process storage, mixing, or management of flow rates or volumes is needed to assist in production of a product.

Table 8 compound means a compound listed in table 8 to subpart G of this part.

Table 9 compound means a compound listed in table 9 to subpart G of this part.

Temperature monitoring device means a unit of equipment used to monitor temperature and having a minimum accuracy of (a) ±1 percent of the temperature being monitored expressed in degrees Celsius ((°C) or (b) ±0.5 degrees (°C), whichever is greater.

The 33/50 program means a voluntary pollution prevention initiative established and administered by the EPA to encourage emissions reductions of 17 chemicals emitted in large volumes by industrial facilities. The EPA Document Number 741–K–92–001 provides more information about the 33/50 program.

Total organic compounds (*TOC),* as used in the process vents provisions, means those compounds measured according to the procedures of Method 18 of appendix A–6 to 40 CFR part 60, ASTM D6420–18 (incorporated by reference, see § 63.14) may be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method.

Total resource effectiveness index value or *TRE index value* means a measure of the supplemental total resource requirement per unit reduction of organic HAP associated with a process vent stream, based on vent stream flow rate, emission rate of organic HAP, net heating value, and corrosion properties (whether or not the vent stream contains halogenated compounds), as quantified by the equations given under § 63.115.

Transfer operation means the loading, into a tank truck or railcar, of organic liquids that contain one or more of the organic hazardous air pollutants listed in table 2 of this subpart from a transfer rack (as defined in this section). Transfer operations do not include loading at an operating pressure greater than 204.9 kilopascals. For each source as defined in this section, the greater than 204.9 kilopascals exemption in this definition no longer applies on and after July 15, 2027.

Transfer rack means the collection of loading arms and loading hoses, at a single loading rack, that are assigned to a chemical manufacturing process unit subject to this subpart according to the procedures specified in § 63.100(h) and are used to fill tank trucks and/or railcars with organic liquids that contain one or more of the organic hazardous air pollutants listed in table 2 to this subpart. Transfer rack includes the associated pumps, meters, shutoff valves, relief valves, and other piping and valves. Transfer rack does not include:

(i) Racks, arms, or hoses that only transfer liquids containing organic hazardous air pollutants as impurities; or

(ii) Racks, arms, or hoses that vapor balance during all loading operations.

Treatment process means a specific technique that removes or destroys the organics in a wastewater or residual stream such as a steam stripping unit, thin-film evaporation unit, waste incinerator, biological treatment unit, or any other process applied to wastewater streams or residuals to comply with § 63.138. Most treatment processes are conducted in tanks. Treatment processes are a subset of waste management units.

Unit operation means one or more pieces of process equipment used to make a single change to the physical or chemical characteristics of one or more process streams. Unit operations include, but are not limited to, reactors, distillation units, extraction columns, absorbers, decanters, dryers, condensers, and filtration equipment.

Vapor balancing system means a piping system that is designed to collect organic hazardous air pollutants vapors displaced from tank trucks or railcars during loading; and to route the collected organic hazardous air pollutants vapors to the storage vessel from which the liquid being loaded originated, or to another storage vessel connected by a common header or to compress and route to a process or a fuel gas system the collected organic hazardous air pollutants vapors.

Vapor collection system, as used in the transfer provisions, means the equipment used to collect and transport organic HAP vapors displaced during the loading of tank trucks or railcars. This does not include the vapor collection system that is part of any tank truck or railcar vapor collection manifold system.

Vapor-mounted seal means a continuous seal that completely covers the annular space between the wall of the storage vessel or waste management unit and the edge of the floating roof and is mounted such that there is a vapor space between the stored liquid and the bottom of the seal.

Vent stream, as used in the process vent provisions, means the gas stream flowing through the process vent.

Waste management unit means the equipment, structure(s), and/or device(s) used to convey, store, treat, or dispose of wastewater streams or residuals. Examples of waste management units include: Wastewater tanks, surface impoundments, individual drain systems, and biological wastewater treatment units. Examples of equipment that may be waste management units include containers, air flotation units, oil-water separators or organic-water separators, or organic removal devices such as decanters, strippers, or thin-film evaporation units. If such equipment is used for recovery then it is part of a chemical manufacturing process unit and is not a waste management unit.

Wastewater means water that:

(i) Contains either:

(A) An annual average concentration of table 9 compounds of at least 5 parts per million by weight and has an annual average flow rate of 0.02 liter per minute or greater, or

(B) An annual average concentration of table 9 compounds of at least 10,000 parts per million by weight at any flow rate, and that

(ii) Is discarded from a chemical manufacturing process unit that meets all of the criteria specified in § 63.100 (b)(1) through (3). Wastewater is process wastewater or maintenance wastewater.

Wastewater stream means a stream that contains only wastewater.

Wastewater tank means a stationary waste management unit that is designed to contain an accumulation of wastewater or residuals and is constructed primarily of non-earthen materials (*e.g.,* wood, concrete, steel, plastic) which provide structural support. Wastewater tanks used for flow equalization are included in this definition.

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.

■ 45. Revise and republish § 63.102 to read as follows:

§ 63.102 General standards.

(a) Except as specified in paragraph (e) of this section, owners and operators of sources subject to this subpart shall comply with the requirements of subparts G and H of this part as specified in paragraphs (a)(1) through (4) of this section.

(1) The provisions set forth in this subpart and subpart G of this part shall apply at all times except during periods of start-up or shutdown (as defined in § 63.101 of this subpart), malfunction, or non-operation of the chemical

manufacturing process unit (or specific portion thereof) resulting in cessation of the emissions to which this subpart and subpart G of this part apply. However, if a start-up, shutdown, malfunction or period of non-operation of one portion of a chemical manufacturing process unit does not affect the ability of a particular emission point to comply with the specific provisions to which it is subject, then that emission point shall still be required to comply with the applicable provisions of this subpart and subpart G of this part during the start-up, shutdown, malfunction or period of non-operation. For example, if there is an overpressure in the reactor area, a storage vessel in the chemical manufacturing process unit would still be required to be controlled in accordance with § 63.119. Similarly, the degassing of a storage vessel would not affect the ability of a process vent to meet the requirements of § 63.113.

(2) The provisions set forth in subpart H of this part shall apply at all times except during periods of start-up or shutdown, malfunction, or process unit shutdown (as defined in § 63.101(b)), or non-operation of the chemical manufacturing process unit (or specific portion thereof) in which the lines are drained and depressurized resulting in cessation of the emissions to which subpart H of this part applies.

(3) The owner or operator shall not shut down items of equipment that are required or utilized for compliance with the provisions of this subpart or subpart G or H of this part during times when emissions (or, where applicable, wastewater streams or residuals) are being routed to such items of equipment, if the shutdown would contravene requirements of this subpart or subpart G or H of this part applicable to such items of equipment. This paragraph does not apply if the item of equipment is malfunctioning, or if the owner or operator must shut down the equipment to avoid damage due to a contemporaneous start-up, shutdown, or malfunction of the chemical manufacturing process unit or portion thereof.

(4) During start-ups, shutdowns, and malfunctions when the requirements of this subpart and subparts G and/or H of this part do not apply pursuant to paragraphs (a)(1) through (3) of this section, the owner or operator shall implement, to the extent reasonably available, measures to prevent or minimize excess emissions to the extent practical. The general duty to minimize emissions during a period of startup, shutdown, or malfunction does not require the owner or operator to achieve emission levels that would be required by the applicable standard at other times if this is not consistent with safety and good air pollution control practices, nor does it require the owner or operator to make any further efforts to reduce emissions if levels required by the applicable 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 (including the startup, shutdown, and malfunction plan required in § 63.6(e)(3)), review of operation and maintenance records, and inspection of the source. The measures to be taken may include, but are not limited to, air pollution control technologies, recovery technologies, work practices, pollution prevention, monitoring, and/or changes in the manner of operation of the source. Back-up control devices are not required but may be used if available.

(b) If, in the judgment of the Administrator, an alternative means of emission limitation will achieve a reduction in organic HAP emissions at least equivalent to the reduction in organic HAP emissions from that source achieved under any design, equipment, work practice, or operational standards in subpart G or H of this part, the Administrator will publish in the **Federal Register** a notice permitting the use of the alternative means for purposes of compliance with that requirement.

(1) The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

(2) Any notice under this paragraph (b) shall be published only after public notice and an opportunity for a hearing.

(3) Any person seeking permission to use an alternative means of compliance under this section shall collect, verify, and submit to the Administrator information showing that the alternative means achieves equivalent emission reductions.

(c) Each owner or operator of a source subject to this subpart shall obtain a permit under 40 CFR part 70 or part 71 from the appropriate permitting authority by the date determined by 40 CFR part 70 or part 71, as appropriate.

(1) If the EPA has approved a State operating permit program under 40 CFR 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.

(2) [Reserved]

(d) The requirements in this subpart and subparts G and H of this part are federally enforceable under section 112 of the Act on and after the dates specified in § 63.100(k) of this subpart.

(e) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), paragraph (a) of this section does not apply. Instead, owners and operators of sources as defined in § 63.101 shall comply with the requirements in this subpart and subparts G and H of this part at all times, except during periods of nonoperation of the source (or specific portion thereof) resulting in cessation of the emissions to which this subpart or subpart G or H of this part applies.

(f) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), at all times, owners and operators must operate and maintain any 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 owners and operators 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.

■ 46. Amend § 63.103 by revising paragraphs (b) introductory text, (b)(1) and (3), adding paragraph (b)(3)(ii), revising and republishing paragraphs (c)(2) and (3), and revising paragraphs (d) through (h) to read as follows:

§ 63.103 General compliance, reporting, and recordkeeping provisions.

* * * * *

(b) Performance tests and initial compliance determinations shall be required only as specified in subparts G and H of this part.

(1) Initial performance tests and compliance determinations shall be conducted according to the schedule and procedures in § 63.7(a) and the applicable sections of subparts G and H of this part. Beginning no later than the compliance dates specified in § 63.100(k)(10), except as outlined in subpart H of this part, conduct subsequent performance tests no later

than 60 calendar months after the previous performance test.

* * * * *

(3) Performance tests shall be conducted as specified in paragraph (b)(3)(i) or (ii) of this section.

(i) Except as specified in paragraph (b)(3)(ii) of this section, performance tests shall be conducted according to the provisions of § 63.7(e), except that performance tests shall be conducted at maximum representative operating conditions for the process. During the performance test, an owner or operator may operate the control or recovery device at maximum or minimum representative operating conditions for monitored control or recovery device parameters, whichever results in lower emission reduction.

(ii) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), paragraph (b)(3)(i) of this section no longer applies and instead the owner or operator may not conduct performance tests during periods of malfunction. Owners and operators 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 such conditions represent normal operation. Upon request, owners and operators must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

* * * * *

(c) * * *

(2) The owner or operator subject to subparts F, G, and H of this part shall keep the records specified in this paragraph, as well as records specified in subparts G and H.

(i) Records of the occurrence and duration of each start-up, shutdown, and malfunction of operation of process equipment or of air pollution control equipment or continuous monitoring systems used to comply with this subpart or subpart G or H of this part during which excess emissions (as defined in § 63.102(a)(4)) occur. For each source as defined in § 63.101, on and after July 15, 2027, this paragraph (c)(2)(i) no longer applies; however, for historical compliance purposes, a copy of these records must be retained and available on-site for at least five years after the date of occurrence.

(ii) For each start-up, shutdown, and malfunction during which excess emissions (as defined in § 63.102(a)(4)) occur, records that the procedures specified in the source's start-up, shutdown, and malfunction plan were followed, and documentation of actions taken that are not consistent with the plan. For example, if a start-up, shutdown, and malfunction plan includes procedures for routing a control device to a backup control device (*e.g.,* the incinerator for a halogenated stream could be routed to a flare during periods when the primary control device is out of service), records must be kept of whether the plan was followed. These records may take the form of a ''checklist,'' or other form of recordkeeping that confirms conformance with the start-up, shutdown, and malfunction plan for the event. For each source as defined in § 63.101, on and after July 15, 2027, this paragraph (c)(2)(ii) no longer applies; however, for historical compliance purposes, a copy of the plan and these records must be retained and available on-site for 5 years after July 15, 2027.

(iii) For continuous monitoring systems used to comply with subpart G of this part, records documenting the completion of calibration checks and maintenance of continuous monitoring systems that are specified in the manufacturer's instructions or other written procedures that provide adequate assurance that the equipment would reasonably be expected to monitor accurately.

(iv) Beginning no later than the compliance dates specified in § 63.100(k)(10), the manufacturer's specifications specified in paragraph (c)(2)(iii) of this section must include a schedule for calibrations, preventative maintenance procedures, a schedule for preventative maintenance, and corrective actions to be taken if a calibration fails. If a continuous monitoring system calibration fails, the continuous monitoring system is considered to be inoperative until the owner or operator takes corrective action and the system passes calibration. The owner or operator must record the nature and cause of instances when the continuous monitoring system is inoperative and the corrective action taken.

(3) Records of start-up, shutdown and malfunction and continuous monitoring system calibration and maintenance are not required if they pertain solely to Group 2 emission points, as defined in § 63.101, that are not included in an emissions average. For each source as defined in § 63.101, on and after July 15, 2027, the phrase ''start-up, shutdown and malfunction and'' in this paragraph (c)(3) no longer applies.

(d) Unless required to be submitted electronically via the EPA's CEDRI, all reports required under this subpart and subparts G and H of this part must be sent to the Administrator at the addresses listed in § 63.13, except that requests for permission to use an alternative means of compliance as provided for in § 63.102(b) of this subpart and application for approval of a nominal efficiency as provided for in § 63.150 (i)(1) through (6) must be submitted to the Director of the EPA Office of Air Quality Planning and Standards rather than to the Administrator or delegated authority.

(1) 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 on or before the specified date.

(2) If acceptable to both the Administrator and the owner or operator of a source, reports may be submitted on electronic media.

(e) The owner or operator of a chemical manufacturing process unit which meets the criteria of § 63.100(b)(1) and (3), but not the criteria of § 63.100(b)(2), shall comply with the requirements of either paragraph (e)(1) or (2) of this section.

(1) Retain information, data, and analysis used to determine that the chemical manufacturing process unit does not use as a reactant or manufacture as a product or co-product any organic hazardous air pollutant. Examples of information that could document this include, but are not limited to, records of chemicals purchased for the process, analyses of process stream composition, engineering calculations, or process knowledge.

(2) When requested by the Administrator, demonstrate that the chemical manufacturing process unit does not use as a reactant or manufacture as a product or co-product any organic hazardous air pollutant.

(f) To qualify for the exemption specified in § 63.100(b)(4), the owner or operator shall maintain the documentation of the information required pursuant to § 63.100(b)(4)(i), and documentation of any update of this information requested by the EPA Regional Office, and shall provide the documentation to the EPA Regional Office upon request. The EPA Regional Office will notify the owner or operator, after reviewing such documentation, if the source does not qualify for the exemption specified in § 63.100(b)(4). In such cases, compliance with subpart H shall be required no later than 90 days after expiration of the applicable compliance date in § 63.100(k)(3), but in no event earlier than 90 days after the date of such notification by the EPA Regional Office. Compliance with this subpart and subpart G of this part shall be no later than April 22, 1997, or as otherwise specified in § 63.100(k)(2)(ii), unless an extension has been granted by the EPA Regional Office or permitting authority as provided in § 63.6(i).

(g) An owner or operator who elects to use the compliance extension provisions of § 63.100(k)(6)(i) or (ii) shall submit a compliance extension request to the appropriate EPA Regional Office no later than 45 days before the applicable compliance date in § 63.100(k)(3), but in no event is submittal required earlier than May 10, 1995. The request shall contain the information specified in § 63.100(k)(5)(iv) and the reason compliance cannot reasonably be achieved without a process unit shutdown, as defined in 40 CFR 63.101 or without replacement of the compressor or recasting of the distance piece.

(h) An owner or operator who elects to use the compliance extension provisions of § 63.100(k)(8) shall submit to the appropriate EPA Regional Office a brief description of the process change, identify the HAP eliminated, and the expected date of cessation of use or production of HAP. The description shall be submitted no later than May 10, 1995, or with the Notice of Compliance Status as required in § 63.182(c), whichever is later.

■ 47. Amend § 63.104 by revising paragraphs (a) and (f) and adding paragraphs (g) through (l) to read as follows:

§ 63.104 Heat exchange system requirements.

(a) Unless one or more of the conditions specified in paragraphs (a)(1) through (6) or paragraph (l) of this section are met, owners and operators of sources subject to this subpart shall monitor each heat exchange system used to cool process equipment in a chemical manufacturing process unit meeting the conditions of § 63.100(b)(1) through (3), except for chemical manufacturing process units meeting the condition specified in § 63.100(c), according to the provisions in either paragraph (b) or (c) of this section, and if applicable, paragraph (g) of this section. Whenever a leak is detected, the owner or operator shall comply with the requirements in paragraph (d) of this section, and if applicable, paragraphs (h) through (j) of this section. Owners and operators of heat exchange systems in a chemical manufacturing process unit meeting the conditions of § 63.100(b)(1) through (3) must also comply with paragraph (k) of this section.

(1) The heat exchange system is operated with the minimum pressure on the cooling water side at least 35 kilopascals greater than the maximum pressure on the process side.

(2) There is an intervening cooling fluid, containing less than 5 percent by weight of total hazardous air pollutants listed in table 4 of this subpart, between the process and the cooling water. This intervening fluid serves to isolate the cooling water from the process fluid and the intervening fluid is not sent through a cooling tower or discharged. For purposes of this section, discharge does not include emptying for maintenance purposes.

(3) The once-through heat exchange system is subject to a National Pollution Discharge Elimination System (NPDES) permit with an allowable discharge limit of 1 part per million or less above influent concentration or 10 percent or less above influent concentration, whichever is greater. For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), this paragraph (a)(3) no longer applies.

(4) Except as specified in paragraph (a)(4)(v) of this section, the once-through heat exchange system is subject to an NPDES permit that:

(i) Requires monitoring of a parameter(s) or condition(s) to detect a leak of process fluids into cooling water;

(ii) Specifies or includes the normal range of the parameter or condition;

(iii) Requires monitoring for the parameters selected as leak indicators no less frequently than monthly for the first six months and quarterly thereafter; and

(iv) Requires the owner or operator to report and correct leaks to the cooling water when the parameter or condition exceeds the normal range.

(v) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), this paragraph (a)(4) no longer applies.

* * * * *

(f)(1) *Required records.* The owner or operator shall retain the records identified in paragraphs (f)(1)(i) through (iv) of this section, and if applicable, paragraph (f)(3) of this section, as specified in § 63.103(c)(1).

(i) Monitoring data required by this section indicating a leak and the date when the leak was detected, and if demonstrated not to be a leak, the basis for that determination;

(ii) Records of any leaks detected by procedures subject to paragraph (c)(2) of this section and the date the leak was discovered;

(iii) The dates of efforts to repair leaks; and

(iv) The method or procedure used to confirm repair of a leak and the date repair was confirmed.

(2) *Reports.* If an owner or operator invokes the delay of repair provisions for a heat exchange system, the following information shall be submitted in the next semi-annual periodic report required by § 63.152(c). If the leak remains unrepaired, the information shall also be submitted in each subsequent periodic report, until repair of the leak is reported. In addition, if an owner or operator is complying with paragraph (g) or (l) of this section, then the semi-annual periodic report must include the information specified in paragraph (f)(2)(vi) of this section.

(i) The owner or operator shall report the presence of the leak by identifying the heat exchange system and the date that the leak was detected.

(ii) The owner or operator shall report whether or not the leak has been repaired.

(iii) The owner or operator shall report the reason(s) for delay of repair. If delay of repair is invoked due to the reasons described in paragraph (e)(2) of this section, documentation of emissions estimates must also be submitted.

(iv) If the leak remains unrepaired, the owner or operator shall report the expected date of repair.

(v) If the leak is repaired, the owner or operator shall report the date the leak was successfully repaired.

(vi) For each heat exchange system subject to paragraph (g) or (l) of this section, the following information must be submitted in each semi-annual periodic report required by § 63.152(c).

(A) The number of heat exchange systems at the plant site subject to the monitoring requirements in paragraph (g) or (l) of this section during the reporting period.

(B) The number of heat exchange systems subject to the monitoring requirements in paragraph (g) or (l) of this section at the plant site found to be leaking during the reporting period.

(C) For each monitoring location where a leak was identified during the reporting period, identification of the monitoring location (*e.g.,* unique monitoring location or heat exchange system ID number), the measured total strippable hydrocarbon concentration (in ppmv as methane) or total hydrocarbon mass emissions rate (in kg/hr as methane) (if complying with paragraph (g) of this section) or the measured concentration of the monitored substance(s) (in ppmv) (if complying with paragraph (l) of this section), the date the leak was first identified, and, if applicable, the date the source of the leak was identified;

(D) 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 or total hydrocarbon mass emissions rate (if complying with paragraph (g) of this section) or the measured concentration of the monitored substance(s) (if complying with paragraph (l) of this section) measured during re-monitoring to verify repair, and the re-monitoring date (*i.e.,* the effective date of repair); and

(E) 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 was completed or is expected to be completed (if the leak is not repaired during the reporting period), the total strippable hydrocarbon concentration or total hydrocarbon mass emissions rate (if complying with paragraph (g) of this section) or the measured concentration of the monitored substance(s) (if complying with paragraph (l) of this section) and date of each monitoring event conducted on the delayed repair during the reporting period, and an estimate in pounds of the potential total hydrocarbon emissions or monitored substance(s) emissions over the reporting period associated with the delayed repair.

(3) *Additional records.* For each heat exchange system subject to paragraph (g) or (l) of this section, owners and operators must also keep records in paragraphs (f)(3)(i) through (iv) of this section.

(i) Monitoring data required by paragraph (g) or (l) of this section that indicate a leak, the date the leak was detected, or, if applicable, the basis for determining there is no leak.

(ii) The dates of efforts to repair leaks.

(iii) The method or procedures used to confirm repair of a leak and the date the repair was confirmed.

(iv) Documentation of delay of repair as specified in paragraphs (f)(3)(iv)(A) through (f)(3)(iv)(D) of this section.

(A) The reason(s) for delaying repair.

(B) A schedule for completing the repair as soon as practical.

(C) The date and concentration or mass emissions rate of the leak as first identified and the results of all subsequent monitoring events during the delay of repair.

(D) An estimate of the potential total hydrocarbon emissions (if monitoring the cooling water for leaks according to paragraph (g)(1) of this section) or monitored substance(s) emissions (if monitoring the cooling water for leaks according to paragraph (l) of this section) from the leaking heat exchange system or heat exchanger for each required delay of repair monitoring interval following the procedures in paragraphs (f)(3)(iv)(D)(*1*) through (*4*) of this section.

(*1*) If an owner or operator complies with the total strippable hydrocarbon concentration leak action level, as specified in paragraph (g)(4) of this section, then the owner or operator must calculate the mass emissions rate by complying with the requirements of paragraph (g)(3)(ii) of this section or by determining 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. If an owner or operator determines the mass flow rate of the cooling water, calculate the mass emissions rate by converting 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'' (incorporated by reference—see § 63.14) and multiply the equivalent liquid concentration by the mass flow rate of the cooling water.

(*2*) For delay of repair monitoring intervals prior to repair of the leak, calculate the potential total hydrocarbon emissions or monitored substance(s) emissions for the leaking heat exchange system or heat exchanger for the monitoring interval by multiplying the mass emissions rate, determined in paragraph (g)(3)(ii) or (f)(3)(iv)(D)(*1*) or (*4*) of this section, 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.

(*3*) For delay of repair monitoring intervals ending with a repaired leak, calculate the potential total hydrocarbon emissions or monitored substance(s) 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 mass emissions rate 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.

(*4*) If an owner or operator monitors the cooling water for leaks according to paragraph (l) of this section, then the owner or operator must calculate the mass emissions rate by determining the mass flow rate of the cooling water at the monitoring location where the leak was detected. Cooling water mass flow rates may be determined using direct measurement, pump curves, heat balance calculations, or other engineering methods. Once determined, multiply the mass flow rate of the cooling water by the concentration of the measured substance(s).

(g) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), owners and operators must monitor the cooling water for the presence of total strippable hydrocarbons that indicate a leak according to paragraph (g)(1) of this section, and if an owner or operator detects a leak pursuant to the procedures in this paragraph, then the owner or operator must repair it according to paragraphs (h) and (i) of this section, unless repair is delayed according to paragraph (j) of this section. The requirements in this paragraph do not apply to heat exchange systems that have a maximum cooling water flow rate of 10 gallons per minute or less.

(1) For each recirculating heat exchange system subject to the requirements of paragraph (g) of this section, owners and operators must collect and analyze a sample from the location(s) described in either paragraph (g)(1)(i) or (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) For each once-through heat exchange system, owners and operators

must collect and analyze a sample from the location(s) described in paragraph (g)(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 (g)(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) If an owner or operator complies with the total strippable hydrocarbon concentration leak action level as specified in paragraph (g)(4) of this section, then the owner or operator must comply with the requirements in paragraph (g)(3)(i) of this section. If an owner or operator complies with the total hydrocarbon mass emissions rate leak action level as specified in paragraph (g)(4) of this section, then the owner or operator must comply with the requirements in paragraphs (g)(3)(i) and (ii) of this section.

(i) Owners and operators must 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'' (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.

(ii) Owners and operators must convert the total strippable hydrocarbon concentration (in ppmv as methane) to a total hydrocarbon mass emissions rate (as methane) using the calculations in Section 7.0 of ''Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources'' (incorporated by reference—see § 63.14).

(4) Except as specified in paragraph (g)(6) of this section, for each heat exchange system, owners and operators must initially monitor monthly for 6-months beginning upon startup and monitor quarterly thereafter using a leak action level defined as a total strippable hydrocarbon concentration (as methane) in the stripping gas of 6.2 ppmv or, for heat exchange systems with a recirculation rate of 10,000 gallons per minute or less, the owner or operator may monitor quarterly using a leak action level defined as a total hydrocarbon mass emissions rate from the heat exchange system (as methane) of 0.18 kg/hr. If a leak is detected as specified in paragraph (g)(5) of this section, then owners and operators must monitor monthly until the leak has been repaired according to the requirements in paragraph (h) or (i) of this section. Once the leak has been repaired according to the requirements in paragraph (h) or (i) of this section, quarterly monitoring for the heat exchange system may resume. The monitoring frequencies specified in this paragraph 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 (g)(2)(ii) of this section.

(5) A leak is defined as described in paragraph (g)(5)(i) or (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 (g)(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 (g)(2)(i) of this section and the measurement value of the corresponding sample taken from the location specified in paragraph (g)(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 paragraph (g)(1)(i) or (ii) or (g)(2)(i) of this section equals or exceeds the leak action level.

(6) For heat exchange systems in ethylene oxide service, as defined in § 63.101, the monitoring frequency is weekly.

(h) If a leak is detected using the methods described in paragraph (g) of this section, owners and operators must repair the leak to reduce the concentration or mass emissions rate to below the applicable leak action level as soon as practicable, but no later than 45 days after identifying the leak, except as specified in paragraph (h)(6) or (j) of this section. Repair must include re-monitoring at the monitoring location where the leak was identified according to the method specified in paragraph (g)(3) of this section to verify that the total strippable hydrocarbon concentration or total hydrocarbon mass emissions rate is below the applicable leak action level. Repair may also include performing the additional monitoring in paragraph (i) of this section to verify that the total strippable hydrocarbon concentration or total hydrocarbon mass emissions rate is below the applicable leak 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.

(6) For heat exchange systems in ethylene oxide service, as defined in § 63.101, paragraph (j) of this section does not apply, and owners and operators must repair the leak to reduce the concentration or mass emissions rate to below the applicable leak action level as soon as practicable, but no later than 15 days after the sample was collected. Delay of repair of heat exchange systems in ethylene oxide service for which leaks have been detected is allowed if the equipment is isolated from the process such that it is no longer in ethylene oxide service.

(i) If an owner or operator detects a leak when monitoring a cooling tower return line under paragraph (g)(1)(i) of this section, then 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 in paragraph (g)(1)(ii) of this section. If no leaks are detected when monitoring according to the requirements of paragraph (g)(1)(ii) of this section, the heat exchange system is considered to have met the repair requirements through re-monitoring of the heat exchange system, as provided in paragraph (h) of this section.

(j) Owners and operators may delay repair when one of the conditions in paragraph (j)(1) or (2) of this section is met and the leak is less than the delay of repair action level specified in paragraph (j)(3) of this section. Owners and operators 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 or total hydrocarbon mass emissions rate is initially and remains less than the delay of repair action level for all monitoring periods during the delay of repair, then the owner or operator may delay repair until the next scheduled shutdown of the heat exchange system. If, during subsequent monitoring, the delay of repair action level is exceeded, then owners and operators 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 or total hydrocarbon mass emissions rate is initially and remains less than the delay of repair action level for all monitoring periods during the delay of repair, then the owner or operator may delay the repair for a maximum of 120 calendar days. Owners and operators must demonstrate that the necessary equipment, parts, or personnel were not available. If, during subsequent monitoring, the delay of repair action level is exceeded, then owners and operators 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 or, for heat exchange systems with a recirculation rate of 10,000 gallons per minute or less, the delay of repair action level is a total hydrocarbon mass emissions rate (as methane) of 1.8 kg/hr. The delay of repair action level is assessed as described in paragraph (j)(3)(i) or (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 (g)(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 (g)(2)(i) of this section and the measurement value of the corresponding sample taken from the location specified in paragraph (g)(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 paragraph (g)(1)(i), (1)(ii), or (2)(i) of this section equals or exceeds the delay of repair action level.

(k) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(11), owners and operators must not inject water into or dispose of water through any heat exchange system in a chemical manufacturing process unit meeting the conditions of § 63.100(b)(1) through (3) if the water contains any amount of ethylene oxide, has been in contact with any process stream containing ethylene oxide, or the water is considered wastewater as defined in § 63.101.

(l) If 99 percent by weight or more of the organic compounds that could leak into the heat exchange system are water soluble and have a Henry's Law Constant less than 5.0E–6 atmospheres-cubic meters/mol at 25 degrees Celsius, beginning no later than the compliance dates specified in § 63.100(k)(10), owners and operators may monitor the cooling water for leaks according to the requirements in paragraph (b) of this section in lieu of using the Modified El Paso Method. If an owner or operator detects a leak according to paragraph (b) of this section, then the owner or operator must repair it according to paragraph (l)(1) of this section, unless repair is delayed according to paragraph (l)(2) of this section.

(1) If a leak is detected using the methods described in paragraph (l) of this section, the owner or operator must repair the leak as soon as practicable, but no later than 45 days after identifying the leak, except as specified in paragraph (l)(2) of this section. Repair must include re-monitoring at the monitoring location where the leak was identified to verify that the criteria in paragraph (b)(6) of this section is no longer met. Actions that can be taken to achieve repair include but are not limited to:

(i) Physical modifications to the leaking heat exchanger, such as welding the leak or replacing a tube;

(ii) Blocking the leaking tube within the heat exchanger;

(iii) Changing the pressure so that water flows into the process fluid;

(iv) Replacing the heat exchanger or heat exchanger bundle; or

(v) Isolating, bypassing, or otherwise removing the leaking heat exchanger from service until it is otherwise repaired.

(2) The owner or operator may delay repair when the conditions in paragraph (e) of this section are met.

■ 48. Amend § 63.105 by revising paragraphs (d) and (e) to read as follows:

§ 63.105 Maintenance wastewater requirements.

* * * * *

(d) The owner or operator shall incorporate the procedures described in paragraphs (b) and (c) of this section as part of the startup, shutdown, and malfunction plan required under § 63.6(e)(3). For each source as defined in § 63.101, on and after July 15, 2027, this paragraph no longer applies.

(e) The owner or operator shall maintain a record of the information required by paragraphs (b) and (c) of this section as part of the start-up, shutdown, and malfunction plan required under § 63.6(e)(3). For each source as defined in § 63.101, on and after July 15, 2027, the phrase "as part of the start-up, shutdown, and malfunction plan required under § 63.6(e)(3)" in this paragraph no longer applies.

■ 49. Amend § 63.107 by revising paragraph (i) and adding paragraph (j) to read as follows:

§ 63.107 Identification of process vents subject to this subpart.

* * * * *

(i) Except as specified in paragraph (j) of this section, the gas stream would meet the characteristics specified in paragraphs (b) through (g) of this section, but, for purposes of avoiding applicability, has been deliberately interrupted, temporarily liquefied, routed through any item of equipment for no process purpose, or disposed of in a flare that does not meet the criteria in § 63.11(b), or an incinerator that does not reduce emissions of organic HAP by 98 percent or to a concentration of 20 parts per million by volume, whichever is less stringent.

(j) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), the phrase "disposed of in a flare that does not meet the criteria in § 63.11(b)" in paragraph (i) of this section is replaced with "disposed of in a flare that does not meet the criteria in § 63.108".

■ 50. Add § 63.108 to read as follows:

§ 63.108 Flare requirements.

(a) For any flare that is used to reduce organic HAP emissions from a chemical manufacturing process unit, the owner or operator may elect to comply with the requirements in this section in lieu of the requirements of § 63.11(b) and the requirements referenced therein. The owner or operator may also elect to comply with the requirements in this section pursuant to the overlap provisions provided in § 63.110(j). However, for each source as defined in

§ 63.101 and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(10), the provisions specified in paragraphs (a)(1) through (22) of this section no longer apply. Instead, if an owner or operator reduces organic HAP emissions from a chemical manufacturing process unit by venting emissions through a closed-vent system to a steam-assisted, air-assisted, non-assisted, or pressure-assisted multi-point flare, then the owner or operator must meet the applicable requirements for flares as specified in §§ 63.670 and 63.671, including the provisions in tables 12 and 13 to subpart CC of this part, except as specified in paragraphs (b) through (o) of this section. This requirement also applies to any flare using fuel gas from a fuel gas system, of which 50 percent or more of the fuel gas is derived from a chemical manufacturing process unit, as determined on an annual average basis. For purposes of compliance with this paragraph, the following terms are defined in § 63.641: Assist air, assist steam, center steam, combustion zone, combustion zone gas, flare, flare purge gas, flare supplemental gas, flare sweep gas, flare vent gas, lower steam, net heating value, perimeter assist air, pilot gas, premix assist air, total steam, and upper steam.

(1) Section 63.107(i) related to criteria in § 63.11(b);

(2) Section 63.113(a)(1);

(3) Section 63.114(a)(2);

(4) Section 63.116(a)(1) through (3);

(5) Section 63.117(a)(5)(i) through (iii);

(6) Section 63.118(f)(5);

(7) The last sentence in § 63.119(e)(1) related to flares;

(8) Section 63.120(e)(1) through (6);

(9) Section 63.122(c)(2) and (g)(3);

(10) Section 63.126(b)(2)(i);

(11) Section 63.127(a)(2);

(12) Section 63.128(b)(1) through (3);

(13) Section 63.129(a)(5)(i) through (iii);

(14) Section 63.130(a)(2)(i), (c), and (d)(5);

(15) Section 63.139(c)(3) and (d)(3);

(16) Section 63.145(j)(1) through (3);

(17) Section 63.146(b)(7)(i)(A) through (C);

(18) V63.147(d)(1);

(19) Section 63.172(d);

(20) Section 63.180(e)(1) through (3);

(21) Section 63.181(g)(1)(iii); and

(22) The phrase ''including periods when a flare pilot light system does not have a flame'' in § 63.181(g)(2)(i) of subpart H of this part.

(b) When determining compliance with the pilot flame requirements specified in § 63.670(b) and (g), substitute ''pilot flame or flare flame'' for each occurrence of ''pilot flame.''

(c) When determining compliance with the flare tip velocity and combustion zone operating limits specified in § 63.670(d) and (e), the requirement effectively applies starting with the 15-minute block that includes a full 15 minutes of the flaring event. The owner or operator is required to demonstrate compliance with the velocity and NHVcz requirements starting with the block that contains the fifteenth minute of a flaring event. The owner or operator is not required to demonstrate compliance for the previous 15-minute block in which the event started and contained only a fraction of flow.

(d) Instead of complying with § 63.670(o)(2)(i), owners and operators must develop and implement the flare management plan no later than the compliance dates specified in § 63.100(k)(10).

(e) Instead of complying with § 63.670(o)(2)(iii), if required to develop a flare management plan and submit it to the Administrator, then owners and operators must also submit all versions of the plan in portable document format (PDF) to the EPA following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Hazardous Organic Chemical Manufacturing Sector Lead.

(f) Section 63.670(o)(3)(ii) and all references to it do not apply. Instead, the owner or operator must comply with the maximum flare tip velocity operating limit at all times.

(g) Substitute ''chemical manufacturing process unit'' for each occurrence of ''petroleum refinery.''

(h) Each occurrence of ''refinery'' does not apply.

(i) If a pressure-assisted multi-point flare is used as a control device, then owners and operators must meet the following conditions:

(1) The owner or operator is not required to comply with the flare tip velocity requirements in § 63.670(d) and (k);

(2) The NHVcz for pressure-assisted mulit-point flares is 800 Btu/scf;

(3) Owners and operators must determine the 15-minute block average NHVvg using only the direct calculation method specified in § 63.670(l)(5)(ii);

(4) Instead of complying with § 63.670(b) and (g), if a pressure-assisted multi-point flare uses cross-lighting on a stage of burners rather than having an individual pilot flame on each burner, then owners and operators must operate each stage of the pressure-assisted multi-point flare with a flame present at all times when regulated material is routed to that stage of burners. Each stage of burners that cross-lights in the pressure-assisted multi-point flare must have at least two pilots with at least one continuously lit and capable of igniting all regulated material that is routed to that stage of burners. Each 15-minute block during which there is at least one minute where no pilot flame is present on a stage of burners when regulated material is routed to the flare is a violation of the standard. Violations in different 15-minute blocks from the same event are considered separate violations. The pilot flame(s) on each stage of burners that use cross-lighting must be continuously monitored by a thermocouple or any other equivalent device used to detect the presence of a flame;

(5) Unless the owner or operator chooses to conduct a cross-light performance demonstration as specified in this paragraph, owners and operators must ensure that if a stage of burners on the flare uses cross-lighting, that the distance between any two burners in series on that stage is no more than 6 feet when measured from the center of one burner to the next burner. A distance greater than 6 feet between any two burners in series may be used provided the owner or operator conducts a performance demonstration that confirms the pressure-assisted multi-point flare will cross-light a minimum of three burners and the spacing between the burners and location of the pilot flame must be representative of the projected installation. The compliance demonstration must be approved by the permitting authority and a copy of this approval must be maintained onsite. The compliance demonstration report must include: a protocol describing the test methodology used, associated test method QA/QC parameters, the waste gas composition and NHVcz of the gas tested, the velocity of the waste gas tested, the pressure-assisted multi-point flare burner tip pressure, the time, length, and duration of the test, records of whether a successful cross-light was observed over all of the burners and the length of time it took for the burners to cross-light, records of maintaining a stable flame after a successful cross-light and the duration for which this was observed, records of any smoking events during the cross-light, waste gas temperature, meteorological conditions (*e.g.,* ambient temperature, barometric pressure, wind speed and direction, and relative humidity), and whether there were any observed flare flameouts; and

(6) Owners and operators must install and operate pressure monitor(s) on the

main flare header, as well as a valve position indicator monitoring system for each staging valve to ensure that the flare operates within the proper range of conditions as specified by the manufacturer. The pressure monitor must meet the requirements in table 13 to subpart CC of this part.

(7) If a pressure-assisted multi-point flare is operating under the requirements of an approved alternative means of emission limitations, owners and operators must either continue to comply with the terms of the alternative means of emission limitations or comply with the provisions in paragraphs (i)(1) through (6) of this section.

(j) If an owner or operator chooses to determine compositional analysis for net heating value with a continuous process mass spectrometer, then the owner or operator must comply with the requirements specified in paragraphs (j)(1) through (7) of this section.

(1) Owners and operators must meet the requirements in § 63.671(e)(2). The owner or operator may augment the minimum list of calibration gas components found in § 63.671(e)(2) with compounds found during a pre-survey or known to be in the gas through process knowledge.

(2) Calibration gas cylinders must be certified to an accuracy of 2 percent and traceable to National Institute of Standards and Technology (NIST) standards.

(3) For unknown gas components that have similar analytical mass fragments to calibration compounds, the owner or operator may report the unknowns as an increase in the overlapped calibration gas compound. For unknown compounds that produce mass fragments that do not overlap calibration compounds, the owner or operator may use the response factor for the nearest molecular weight hydrocarbon in the calibration mix to quantify the unknown component's NHVvg.

(4) The owner or operator may use the response factor for n-pentane to quantify any unknown components detected with a higher molecular weight than n-pentane.

(5) Owners and operators must perform an initial calibration to identify mass fragment overlap and response factors for the target compounds.

(6) Owners and operators must meet applicable requirements in Performance Specification 9 in appendix B to part 60 of this chapter for continuous monitoring system acceptance including, but not limited to, performing an initial multi-point calibration check at three concentrations following the procedure in section 10.1 and performing the periodic calibration requirements listed for gas chromatographs in table 13 to subpart CC of this part, for the process mass spectrometer. The owner or operator may use the alternative sampling line temperature allowed under Net Heating Value by Gas Chromatograph in table 13 to subpart CC of this part.

(7) The average instrument calibration error (CE) for each calibration compound at any calibration concentration must not differ by more than 10 percent from the certified cylinder gas value. The CE for each component in the calibration blend must be calculated using equation 1 to this paragraph.

Equation 1 to Paragraph (j)(7)

$$CE = \frac{C_m - C_a}{C_a} x\, 100 \text{ (Eq. 1)}$$

Where:

C_m = Average instrument response (ppm)
C_a = Certified cylinder gas value (ppm)

(k) If an owner or operator use a gas chromatograph or mass spectrometer for compositional analysis for net heating value, then the owner or operator may choose to use the CE of $NHV_{measured}$ versus the cylinder tag value NHV as the measure of agreement for daily calibration and quarterly audits in lieu of determining the compound-specific CE. The CE for NHV at any calibration level must not differ by more than 10 percent from the certified cylinder gas value. The CE for must be calculated using equation 2 to this paragraph.

Equation 2 to Paragraph (k)

$$CE = \frac{NHV_{measured} - NHV_a}{NHV_a} x\, 100 \text{ (Eq. 2)}$$

Where:

$NHV_{measured}$ = Average instrument response (Btu/scf)
NHV_a = Certified cylinder gas value (Btu/scf)

(l) Instead of complying with § 63.670(q), owners and operators must comply with the reporting requirements specified in paragraphs (l)(1) and (2) of this section.

(1) The initial notification requirements specified in § 63.152(b)(7).

(2) The Periodic Report required by § 63.152(c) must include the items specified in paragraphs (l)(2)(i) through (vi) of this section.

(i) Records as specified in paragraph (m)(1) 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 or flare flame is present. Include the start and stop time and date of each 15-minute block.

(ii) Visible emission records as specified in paragraph (m)(2)(iv) of this section for each period of 2 consecutive hours during which visible emissions exceeded a total of 5 minutes. Indicate the date and start and end times for each period.

(iii) The periods specified in paragraph (m)(6) of this section. Indicate the date and start and end times for each period, and 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) and paragraph (f) of this section:

(A) The start and stop time and date of the flaring event.

(B) The length of time in minutes for which emissions were visible from the flare during the event.

(C) For steam-assisted, air-assisted, and non-assisted flares, the start date, start time, and duration in minutes for 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 in ft/sec 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.

(v) For pressure-assisted multi-point flares, the periods of time when the pressure monitor(s) on the main flare header show the burners operating outside the range of the manufacturer's specifications. Indicate the date and start and end times for each period.

(vi) For pressure-assisted multi-point flares, the periods of time when the staging valve position indicator monitoring system indicates a stage should not be in operation and is or when a stage should be in operation and is not. Indicate the date and start and end times for each period.

(m) Instead of complying with § 63.670(p), owners and operators must keep the flare monitoring records specified in paragraphs (m)(1) through (14) of this section.

(1) Retain records of the output of the monitoring device used to detect the presence of a pilot flame or flare flame as required in § 63.670(b) and the presence of a pilot flame as required in paragraph (i)(4) of this section 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 or flare flame is present when regulated material is routed to a flare for a minimum of 5 years. For a pressure-assisted multi-point flare that uses cross-lighting, retain records of each 15-minute block during which there was at least one minute that no pilot flame is present on each stage when regulated material is routed to a flare for a minimum of 5 years. The owner or operator may reduce the collected minute-by-minute data to a 15-minute block basis with an indication of whether there was at least one minute where no pilot flame or flare flame was present.

(2) Retain records of daily visible emissions observations as specified in paragraphs (m)(2)(i) through (iv) of this section, as applicable, for a minimum of 3 years.

(i) To determine when visible emissions observations are required, the record must identify all periods when regulated material is vented to the flare.

(ii) If visible emissions observations are performed using Method 22 in appendix A–7 to part 60 of this chapter, then the record must identify whether the visible emissions observation was performed, the results of each observation, total duration in minutes of observed visible emissions, and whether it was a 5-minute or 2-hour observation. Record the date and start time of each visible emissions observation.

(iii) If a video surveillance camera is used pursuant to § 63.670(h)(2), then the record must include all video surveillance images recorded, with time and date stamps.

(iv) For each 2-hour period for which visible emissions are observed for more than 5 minutes in 2 consecutive hours, then the record must include the date and start and end 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.

(3) 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, then 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, then 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.

(4) The flare vent gas compositions specified to be monitored under § 63.670(j). Retain records of individual component concentrations from each compositional analysis for a minimum of 2 years. If an NHVvg analyzer is used, retain records of the 15-minute block average values for a minimum of 5 years.

(5) Each 15-minute block average operating parameter calculated following the methods specified in § 63.670(k) through (n) as applicable.

(6) All periods during which operating values are outside of the applicable operating limits specified in § 63.670(d) through (f) and paragraph (i) of this section when regulated material is being routed to the flare.

(7) All periods during which the owner or operator does not perform flare monitoring according to the procedures in § 63.670(g) through (j).

(8) For pressure-assisted multi-point flares, if a stage of burners on the flare uses cross-lighting, then a record of any changes made to the distance between burners.

(9) For pressure-assisted multi-point flares, all periods when the pressure monitor(s) on the main flare header show burners are operating outside the range of the manufacturer's specifications. Indicate the date and time for each period, the pressure measurement, the stage(s) and number of burners affected, and the range of manufacturer's specifications.

(10) For pressure-assisted multi-point flares, all periods when the staging valve position indicator monitoring system indicates a stage of the pressure-assisted multi-point flare should not be in operation and when a stage of the pressure-assisted multi-point flare should be in operation and is not. Indicate the date and time for each period, whether the stage was supposed to be open, but was closed or vice versa, and the stage(s) and number of burners affected.

(11) 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.

(12) 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.

(13) Records of the root cause analysis and corrective action analysis conducted as required in § 63.670(o)(3) and paragraph (f) of this section, including an identification of the affected flare, 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).

(14) 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.

(n) The owner or operator may elect to comply with the alternative means of emissions limitation requirements specified in § 63.670(r) in lieu of the requirements in § 63.670(d) through (f), as applicable. However, instead of complying with § 63.670(r)(3)(iii), owners and operators must also submit the alternative means of emissions limitation request 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 (C404–02), Attention: Hazardous Organic Chemical Manufacturing Sector Lead, 4930 Old Page Rd., Durham, NC 27703.

(o) The referenced provisions specified in paragraphs (o)(1) through (4) of this section do not apply when demonstrating compliance with this section.

(1) Section 63.670(o)(4)(iv) of subpart CC of this part.

(2) The last sentence of § 63.670(o)(6).

(3) The phrase ''that were not caused by a *force majeure* event'' in § 63.670(o)(7)(ii).

(4) The phrase ''that were not caused by a *force majeure* event'' in § 63.670(o)(7)(iv).

■ 51. Add § 63.109 to read as follows:

§ 63.109 Procedures for determining whether process vents, storage vessels, equipment, wastewater, and heat exchange systems are in ethylene oxide service.

This section applies beginning no later than the compliance dates specified in § 63.100(k)(11). To determine if process vents, storage vessels, equipment leaks, wastewater, and heat exchange systems are in ethylene oxide service, as defined in § 63.101, owners and operators must comply with the requirements in paragraphs (a) through (e) of this section, as applicable.

(a) Except as specified in paragraph (a)(7) of this section, for each Group 1 and Group 2 process vent stream, owners and operators must measure the flow rate and concentration of ethylene oxide of each process vent as specified in paragraphs (a)(1) through (6) of this section.

(1) Measurements must be made prior to any dilution of the vent streams.

(2) Measurements may be made on the combined vent streams at a chemical manufacturing process unit or for each separate vent stream.

(3) The sampling site shall be after the last recovery device (if any recovery devices are present) but prior to the inlet of any control device that is present and prior to release to the atmosphere. Method 1 or 1A of appendix A–1 to part 60 of this chapter, as appropriate, must be used for the selection of the sampling sites. For vents smaller than 0.10 meter in diameter, sample at one point at the center of the duct.

(4) The gas volumetric flow rate must be determined using Method 2, 2A, 2C, 2D, 2F, or 2G of appendices A–1 and A–2 to part 60 of this chapter (respectively), as appropriate.

(5) Except as specified in paragraph (a)(6) of this section, the concentration of ethylene oxide must be determined using Method 18 of appendix A–6 to part 60 of this chapter, or Method 320 of appendix A to this part.

(6) You may elect to use ASTM D6348–12 (Reapproved 2020) (incorporated by reference, § 63.14) in lieu of Method 320 of appendix A to this part as specified in paragraph (a)(5) of this section. To comply with this paragraph, annexes Al through A8 to ASTM D6348–12 (Reapproved 2020) are mandatory; the percent (%) R must be determined for each target analyte using Equation A5.5 of ASTM D6348–12 (Reapproved 2020) Annex A5 (Analyte Spiking Technique); and in order for the test data to be acceptable for a compound, the %R must be 70% ≥ R ≤ 130%. If the %R value does not meet this criterion for a target compound, then 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:

Equation 1 to Paragraph (a)(6)

$$\text{Reported Results} = (\text{Measured Concentration in the Stack} \times 100)/\%R.$$

(7) The requirements specified in paragraphs (a)(1) through (6) of this section for an initial measurement or initial performance test do not apply if the conditions specified in paragraphs (a)(7)(i) through (iv) of this section are met for a previously conducted measurement or performance test.

(i) No changes have been made to the process since the time of the measurement or performance test;

(ii) The operating conditions and test methods used during measurement or performance test conform to the ethylene oxide related requirements of this subpart;

(iii) The control device and process parameter values established during the previously conducted measurement or performance test are used to demonstrate continuous compliance with the ethylene oxide related requirements of this subpart; and

(iv) The previously conducted measurement or performance test was completed within the last 60 months.

(b) For storage vessels, owners and operators must determine the concentration of ethylene oxide of the fluid stored in the storage vessels by complying with the requirements in paragraph (b)(1) or (2) of this section.

(1) The owner or operator must measure concentration of ethylene oxide of the fluid stored in the storage vessel using Method 624.1 of appendix A to 40 CFR part 136, or preparation by Method SW–846–5031 or SW–846–5030B and analysis by Method SW–846–8260D (incorporated by reference, see § 63.14). The owner or operator may not use a preservative in the collected sample; the owner or operator must store the sample with minimal headspace as cold as possible and at least below 4 degrees C; and the owner or operator must analyze the sample as soon as possible, but in no case longer than 7 days from the time the sample was collected. If owners and operators collect a sample from a pressure vessel, then the owner or operator must maintain the sample under pressure both during and following sampling.

(2) Unless specified by the Administrator, the owner or operator may calculate the concentration of ethylene oxide of the fluid stored in the storage vessels if information specific to the fluid stored is available. Information specific to the fluid stored includes concentration data from safety data sheets.

(c) For equipment leaks, owners and operators must comply with the requirements in paragraphs (c)(1) through (4) of this section.

(1) Each piece of equipment within a chemical manufacturing process unit that can reasonably be expected to contain equipment in ethylene oxide service is presumed to be in ethylene oxide service unless the owner or operator demonstrates that the piece of equipment is not in ethylene oxide service. For a piece of equipment to be considered not in ethylene oxide service, it must be determined that the percent ethylene oxide content of the process fluid that is contained in or contacts equipment can be reasonably expected to not exceed 0.1 percent by weight on an annual average basis. For purposes of determining the percent ethylene oxide content of the process fluid, owners and operators must use Method 18 of appendix A–6 to part 60 of this chapter, for gaseous process fluid, and Method 624.1 of appendix A to part 136 of this chapter, or preparation by Method SW–846–5031 and analysis by Method SW–846–8260D (both incorporated by reference, see § 63.14) for liquid process fluid. In lieu of preparation by Method SW–846–5031, owners and operators may use Method SW–846–5030B (incorporated by reference, see § 63.14), as long as: the owner or operator does not use a

preservative in the collected sample; the owner or operator stores the sample with minimal headspace as cold as possible and at least below 4 degrees C; and the owner or operator analyzes the sample as soon as possible, but in no case longer than 7 days from the time the sample was collected.

(2) Unless specified by the Administrator, owners and operators may use good engineering judgment rather than the procedures specified in paragraph (c)(1) of this section to determine that the percent ethylene oxide content of the process fluid that is contained in or contacts equipment does not exceed 0.1 percent by weight.

(3) Owners and operators may revise a determination for whether a piece of equipment is in ethylene oxide service by following the procedures in paragraph (c)(1) of this section, or by documenting that a change in the process or raw materials no longer causes the equipment to be in ethylene oxide service.

(4) Samples used in determining the ethylene oxide content must be representative of the process fluid that is contained in or contacts the equipment.

(d) For wastewater, owners and operators must determine the concentration of ethylene oxide of each wastewater stream using Method 624.1 of appendix A to part 136 of this chapter, or preparation by either Method SW–846–5031 or SW–846–5030B and analysis by Method SW–846–8260D (incorporated by reference, see § 63.14). The owner or operator may not use a preservative in the collected sample; the owner or operator must store the sample with minimal headspace as cold as possible and at least below 4 degrees C; and the owner or operator must analyze the sample as soon as possible, but in no case longer than 7 days from the time the sample was collected.

(e) For heat exchange systems, owners and operators must comply with the requirements in paragraph (e)(1) or (2) of this section.

(1) Determine the concentration of ethylene oxide of the process fluid cooled by the heat exchange system using Method 624.1 of appendix A to part 136 of this chapter, or preparation by either Method SW–846–5031 or SW–846–5030B and analysis by Method SW–846–8260D (incorporated by reference, see § 63.14). The owner or operator may not use a preservative in the collected sample; the owner or operator must store the sample with minimal headspace as cold as possible and at least below 4 degrees C; and the owner or operator must analyze the sample as soon as possible, but in no case longer than 7 days from the time the sample was collected. soon as possible, but in no case longer than 7 days from the time the sample was collected.

(2) Unless specified by the Administrator, owners and operators may use good engineering judgment rather than the procedures specified in paragraph (e)(1) of this section to determine that the percent ethylene oxide content of the process fluid cooled by the heat exchange system does not exceed 0.1 percent by weight.

■ 52. Amend table 3 to subpart F by:

■ a. Revising entries ''63.6(d)'', ''63.6(e)'', ''63.6(e)(1)(i)'', ''63.6(e)(1)(ii)'', ''63.6(e)(2)'', ''63.6(e)(3)(i)'', ''63.6(e)(3)(i)(B)'', ''63.6(e)(3)(i)(C)'', ''63.6(e)(3)(ii)'', ''63.6(e)(3)(vi)'' and ''63.6(e)(3)(vii)'';

■ b. Removing entries ''63.6(e)(3)(vii)(A)'', ''63.6(e)(3)(vii)(B)'' and ''63.6(e)(3)(vii)(C)'';

■ c. Revising entries ''63.6(e)(3)(viii)'', ''63.6(e)(3)(ix)'' and ''63.6(f)(1)'',

■ d. Adding the entry for ''63.7(a)(4)''; and

■ e. Revising entries ''63.7(e)(1)'', ''63.7(f)'', ''63.8(a)(3)'', ''63.8(a)(4)'', ''63.8(c)(1)(i)'', ''63.8(c)(1)(iii)'', ''63.9(k)'', ''63.10(d)(5)'' and ''63.11–63.15''.

The revisions and additions read as follows:

TABLE 3 TO SUBPART F OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPARTS F, G, AND H[A] TO SUBPART F

Reference	Applies to subparts F, G, and H	Comment
* * * * * * *		
63.6(d)	[Reserved].	
63.6(e)	Yes[c]	Except as otherwise specified for individual paragraphs. Does not apply to Group 2 emission points unless they are included in an emissions average.[b][c]
63.6(e)(1)(i)	No	This is addressed by § 63.102(a)(4) and (f) of subpart F.
63.6(e)(1)(ii)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	
* * * * * * *		
63.6(e)(2)	[Reserved].	
63.6(e)(3)(i)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	
* * * * * * *		
63.6(e)(3)(i)(B)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	
63.6(e)(3)(i)(C)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	
63.6(e)(3)(ii)	[Reserved].	
* * * * * * *		
63.6(e)(3)(vi)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	
63.6(e)(3)(vii)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	
63.6(e)(3)(viii)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	
63.6(e)(3)(ix)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	

TABLE 3 TO SUBPART F OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPARTS F, G, AND H [a] TO SUBPART F—Continued

Reference	Applies to subparts F, G, and H	Comment
63.6(f)(1)	No	§ 63.102(a) and (e) of subpart F specifies when the standards apply.
*	* * *	* * *
63.7(a)(4)	Yes.	
*	* * *	* * *
63.7(e)(1)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	See § 63.103(b)(3).
*	* * *	* * *
63.7(f)	Yes.	
*	* * *	* * *
63.8(a)(3)	[Reserved].	
63.8(a)(4)	Yes, except for flares subject to § 63.108.	
*	* * *	* * *
63.8(c)(1)(i)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	
*	* * *	* * *
63.8(c)(1)(iii)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	
*	* * *	* * *
63.9(k)	Yes.	
*	* * *	* * *
63.10(d)(5)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	Except that, before July 15, 2027, reports required by § 63.10(d)(5) shall be submitted at the time specified in § 63.152(d) of subpart G and in § 63.182(d) of subpart H.
*	* * *	* * *
63.11–63.15	Yes, except 63.11(b) does not apply to flares subject to § 63.108.	

[a] Wherever subpart A 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 necessarily required.

[b] Except as specified in footnote c of this table, the plan, and any records or reports of start-up, shutdown, and malfunction do not apply to Group 2 emission points unless they are included in an emissions average.

[c] On and after July 15, 2027, footnote b of this table does not apply and the row for the "63.6(e)" entry of this table is no longer applicable.

Table 4 to Subpart F of Part 63 [Amended]

■ 53. Amend table 4 to subpart F by removing the entry for ''Ethylene glycol monobutyl ether''.

■ 54. Revise the heading to subpart G to read as follows:

Subpart G—National Emission Standards for Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater

■ 55. Amend § 63.110 by:

■ a. Revising paragraphs (b)(3) and (c)(2)(i);

■ b. Revising paragraphs (d)(2) introductory text, (d)(3), (d)(5) introductory text, (d)(6), (d)(8) introductory text, and (d)(9);

■ c. Revising paragraphs (e)(1) introductory text, (f)(2) introductory text, (f)(3), (f)(4) introductory text and (h);

■ d. Revising paragraphs (i) introductory text, and (i)(1)(iv); and

■ e. Adding paragraph (j).

The revisions and addition read as follows:

§ 63.110 Applicability.

* * * * *

(b) * * *

(3) Except as specified in paragraph (j) of this section, after the compliance dates specified in § 63.100, a Group 2 storage vessel that is also subject to the provisions of 40 CFR part 61, subpart Y is required to comply only with the provisions of part 61, subpart Y, of this chapter. The recordkeeping and reporting requirements of part 61, subpart Y, will be accepted as compliance with the recordkeeping and reporting requirements of this subpart.

(c) * * *

(2) * * *

(i) Except as provided in paragraph (j) of this section, if the transfer rack is subject to the control requirements specified in § 61.302 of this chapter, then the transfer rack is required to comply with the control requirements of § 61.302. The owner or operator may elect to comply with either the associated testing, monitoring, reporting, and recordkeeping requirements of part 61, subpart BB, of this chapter or with the testing, monitoring, recordkeeping, and reporting requirements specified in this subpart for Group 1 transfer racks. The owner or operator shall indicate this decision in either the Notification of Compliance Status specified in § 63.152(b) or in an operating permit application or amendment.

* * * * *

(d) * * *

(2) After the compliance dates specified in § 63.100, the owner or

operator of a Group 2 process vent that is also subject to the provisions of part 60, subpart III, of this chapter shall determine requirements according to paragraphs (d)(2)(i) and (ii) of this section. For each source as defined in § 63.101, on and after July 15, 2027, this paragraph no longer applies.

* * * * *

(3) After the compliance dates specified in 63.100, if an owner or operator of a process vent subject to this subpart that is also subject to the provisions of part 60, subpart III, of this chapter elects to control the process vent to the levels required in § 63.113(a)(1) or (2) without calculating the TRE index value for the vent according to the procedures specified in § 63.115(d), then the owner or operator shall comply with the testing, monitoring, reporting, and recordkeeping provisions of this subpart and shall be exempt from the testing, monitoring, reporting, and recordkeeping provisions of part 60, subpart III. For each source as defined in § 63.101, on and after July 15, 2027, this paragraph no longer applies.

* * * * *

(5) After the compliance dates specified in § 63.100, the owner or operator of a Group 2 process vent that is also subject to the provisions of 40 CFR part 60, subpart NNN shall determine requirements according to paragraphs (d)(5)(i) and (ii) of this section. For each source as defined in § 63.101, on and after July 15, 2027, this paragraph no longer applies.

* * * * *

(6) After the compliance dates specified in § 63.100, if an owner or operator of a process vent subject to this subpart that is also subject to the provisions of part 60, subpart NNN, of this chapter elects to control the process vent to the levels required in § 63.113(a)(1) or (2) without calculating the TRE index value for the vent according to the procedures specified in § 63.115(d), then the owner or operator shall comply with the testing, monitoring, reporting, and recordkeeping provisions of this subpart and shall be exempt from the testing, monitoring, reporting, and recordkeeping provisions of part 60, subpart NNN. For each source as defined in § 63.101, on and after July 15, 2027, this paragraph no longer applies.

* * * * *

(8) After the compliance dates specified in § 63.100, the owner or operator of a Group 2 process vent that is also subject to the provisions of part 60, subpart RRR, of this chapter shall determine requirements according to paragraphs (d)(8)(i) and (ii) of this section. For each source as defined in § 63.101, on and after July 15, 2027, this paragraph no longer applies.

* * * * *

(9) After the compliance dates specified in § 63.100, if an owner or operator of a process vent subject to this subpart that is also subject to the provisions of part 60, subpart RRR, of this chapter elects to control the process vent to the levels required in § 63.113(a)(1) or (2) without calculating the TRE index value for the vent according to the procedures specified in § 63.115(d), then the owner or operator shall comply with the testing, monitoring, reporting, and recordkeeping provisions of this subpart and shall be exempt from the testing, monitoring, reporting, and recordkeeping provisions of part 60, subpart RRR. For each source as defined in § 63.101, on and after July 15, 2027, this paragraph no longer applies.

* * * * *

(e) * * *

(1) Except as specified in paragraph (j) of this section, after the compliance dates specified in § 63.100, the owner or operator of a Group 1 or Group 2 wastewater stream that is also subject to the provisions of part 61, subpart FF, of this chapter is required to comply with the provisions of both this subpart and part 61, subpart FF. Alternatively, the owner or operator may elect to comply with the provisions of paragraphs (e)(1)(i) and (ii) of this section, which shall constitute compliance with the provisions of part 61, subpart FF.

* * * * *

(f) * * *

(2) Except as specified in paragraph (j) of this section, after the compliance dates specified in § 63.100, the owner or operator of any Group 2 process vent that is also subject to the provisions of part 61, subpart F, of this chapter shall comply with the provisions specified in either paragraph (f)(2)(i) or (ii) of this section.

* * * * *

(3) After the compliance dates specified in § 63.100, if an owner or operator of a process vent subject to this subpart that is also subject to the provisions of part 61, subpart F, of this chapter elects to control the process vent to the levels required in § 63.113(a)(1) or (2) without calculating the TRE index value for the vent according to the procedures specified in § 63.115(d), then the owner or operator shall comply with the testing, monitoring, reporting, and recordkeeping provisions of this subpart and shall be exempt from the testing, monitoring, reporting, and recordkeeping provisions of part 61, subpart F. For each source as defined in § 63.101, on and after July 15, 2027, this paragraph no longer applies.

(4) Except as specified in paragraph (j) of this section, after the compliance dates specified in § 63.100, the owner or operator of a Group 1 or Group 2 wastewater stream that is also subject to the provisions of 40 CFR part 61, subpart F shall comply with the provisions of either paragraph (f)(4)(i) or (ii) of this section.

* * * * *

(h) *Overlap with other regulations for monitoring, recordkeeping, or reporting with respect to combustion devices, recovery devices, or recapture devices.* (1) Except as specified in paragraph (h)(2) of this section, after the compliance dates specified in § 63.100, if any combustion device, recovery device, or recapture device subject to this subpart is also subject to monitoring, recordkeeping, and reporting requirements in part 264, subpart AA or CC, of this chapter or is subject to monitoring and recordkeeping requirements in part 265, subpart AA or CC, of this chapter and the owner or operator complies with the periodic reporting requirements under 40 CFR part 264, subpart AA or CC that would apply to the device if the facility had final-permitted status, the owner or operator may elect to comply either with the monitoring, recordkeeping, and reporting requirements of this subpart, or with the monitoring, recordkeeping, and reporting requirements in parts 264 and/or 265, as described in this paragraph, which shall constitute compliance with the monitoring, recordkeeping, and reporting requirements of this subpart. The owner or operator shall identify which option has been selected in the Notification of Compliance Status required by § 63.152(b).

(2) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10) of subpart F of this part, paragraph (h)(1) of this section no longer applies.

(i) *Alternative means of compliance*—For each source as defined in § 63.101, on and after July 15, 2027, this paragraph (i) no longer applies.

(1) * * *

(iv) For equipment, comply with § 63.160(g).

* * * * *

(j) *Overlap with other regulations for flares.* (1) For each source as defined in § 63.101, beginning no later than the compliance dates specified in

§ 63.100(k)(10), flares used as a control device to comply with the overlap provisions in either paragraph (b)(3), (c)(2)(i), (e)(1), (f)(2)(i), (f)(2)(ii), or (f)(4)(i) or (ii) of this section must comply with the provisions specified in § 63.108 and are no longer subject to any flare related provisions of part 61, subparts F, Y, BB, and FF, of this chapter or § 60.18 of this chapter.

(2) Owners and operators of flares that are subject to the flare related requirements of this subpart and flare related requirements of any other regulation in part 60, 61, or 63 of this chapter, may elect to comply with the requirements in § 63.108 in lieu of all flare related requirements in any other regulation in part 60, 61, or 63.

■ 56. Revise § 63.111 to read as follows:

§ 63.111 Definitions.

All terms used in this subpart shall have the meaning given them in the Act and in subpart F of this part.

■ 57. Revise and republish § 63.113 to read as follows:

§ 63.113 Process vent provisions—reference control technology.

(a) The owner or operator of a Group 1 process vent as defined in this subpart shall comply with the requirements of paragraph (a)(1), (2), (3), or (4) of this section, and paragraph (a)(5) of this section. The owner or operator who transfers a gas stream that has the characteristics specified in § 63.107(b) through (h) or meets the criteria specified in § 63.107(i) to an off-site location or an on-site location not owned or operated by the owner or operator of the source for disposal shall comply with the requirements of paragraph (i) of this section.

(1) Reduce emissions of organic HAP using a flare.

(i) Except as specified in § 63.108(a), the flare shall comply with the requirements of § 63.11(b).

(ii) Halogenated vent streams, as defined in § 63.111, shall not be vented to a flare.

(2) Reduce emissions of total organic hazardous air pollutants by 98 weight-percent or to a concentration of 20 parts per million by volume. For combustion devices, the emission reduction or concentration shall be calculated on a dry basis, corrected to 3-percent oxygen, and compliance can be determined by measuring either organic hazardous air pollutants or total organic carbon using the procedures in § 63.116.

(i) Compliance with paragraph (a)(2) of this section may be achieved by using any combination of combustion, recovery, and/or recapture devices, except that a recovery device may not be used to comply with paragraph (a)(2) of this section by reducing emissions of total organic hazardous air pollutants by 98 weight-percent, except as provided in paragraph (a)(2)(ii) of this section.

(ii) An owner or operator may use a recovery device, alone or in combination with one or more combustion or recapture devices, to reduce emissions of total organic hazardous air pollutants by 98 weight-percent if all the conditions of paragraphs (a)(2)(ii)(A) through (a)(2)(ii)(D) of this section are met.

(A) The recovery device (and any combustion device or recapture device which operates in combination with the recovery device to reduce emissions of total organic hazardous air pollutants by 98 weight-percent) was installed before the date of proposal of the subpart of this part 63 that makes this subpart G applicable to process vents in the chemical manufacturing process unit.

(B) The recovery device that will be used to reduce emissions of total organic hazardous air pollutants by 98 weight-percent is the last recovery device before emission to the atmosphere.

(C) The recovery device, alone or in combination with one or more combustion or recapture devices, is capable of reducing emissions of total organic hazardous air pollutants by 98 weight-percent, but is not capable of reliably reducing emissions of total organic hazardous air pollutants to a concentration of 20 parts per million by volume.

(D) If the owner or operator disposed of the recovered material, the recovery device would comply with the requirements of this subpart for recapture devices.

(3) Except as specified in paragraph (a)(4) of this section, achieve and maintain a TRE index value greater than 1.0 at the outlet of the final recovery device, or prior to release of the vent stream to the atmosphere if no recovery device is present. If the TRE index value is greater than 1.0, the process vent shall comply with the provisions for a Group 2 process vent specified in either paragraph (d) or (e) of this section, whichever is applicable.

(4) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), the provisions specified in paragraphs (a)(4)(i) through (xv) of this section no longer apply. Instead, an owner or operator of a Group 1 process vent as defined in § 63.101 must comply with the requirements of paragraph (a)(1) or (2) of this section; and an owner or operator of a Group 2 process vent as defined in § 63.101 must comply with the requirements of paragraph (f) or (g) of this section.

(i) Paragraphs (a)(3), (d), and (e) of this section;

(ii) Section 63.114(b) and (c)(2);

(iii) Section 63.115(d), except (d)(2)(v);

(iv) The following phrases in § 63.115(e): "TRE index value", "changes that are within the range on which the original TRE calculation was based", and "the recalculated TRE index value is less than or equal to 1.0, or less than or equal to 4.0 but greater than 1.0";

(v) The following phrases in § 63.115(f): "TRE index value", and "regardless of the TRE index value determined at the location specified in § 63.115(a)";

(vi) The last two sentences in § 63.115(f)(2): "If the combined vent stream is a Group 2 process vent as determined by the previous sentence, but one or more of the HON streams, or combinations of HON streams, has a TRE index value greater than 1 but less than or equal to 4, the combined vent stream is a process vent with a TRE index value greater than 1 but less than or equal to 4. In this case, the owner or operator shall monitor the combined vent stream as required by § 63.114(b).";

(vii) The phrase in § 63.117(a): "or the provisions for Group 2 process vents with a TRE index value greater than 1.0 but less than or equal to 4.0 in § 63.113(d)";

(viii) The phrase in § 63.117(a)(3): "TRE determinations or";

(ix) Section 63.117(a)(7) and (b);

(x) Section 63.118(b), (c), (d)(3), (e)(3), (h), (i), (j), and (k)(4);

(xi) The following phrase in § 63.118(g)(2): "and TRE index value";

(xii) The last sentence in § 63.150(g)(2)(iii)(B)(*2*);

(xiii) The phrase in § 63.150(m)(2)(i): "and TRE index value";

(xiv) The last sentence in § 63.151(d)(6)(i); and

(xv) Table 4 to subpart G of this part.

(5) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), an owner or operator of a Group 1 process vent as defined in § 63.101 that contains chlorine, hydrogen chloride, or any other chlorinated compound must reduce emissions of dioxins and furans (toxic equivalency basis) to a concentration of 0.054 nanograms per standard cubic meter on a dry basis corrected to 3 percent oxygen.

(b) If a boiler or process heater is used to comply with the percent 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.

(c) Halogenated vent streams from Group 1 process vents that are combusted shall be controlled according to paragraph (c)(1) or (2) of this section.

(1) If a combustion device is used to comply with paragraph (a)(2) of this section for a halogenated vent stream, then the gas stream exiting the combustion device shall be conveyed to a halogen reduction device, such as a scrubber, before it is discharged to the atmosphere.

(i) Except as provided in paragraph (c)(1)(ii) of this section, the halogen reduction device shall reduce overall emissions of hydrogen halides and halogens, as defined in § 63.111 of this subpart, by 99 percent or shall reduce the outlet mass of total hydrogen halides and halogens to less than 0.45 kilogram per hour.

(ii) If a scrubber or other halogen reduction device was installed prior to December 31, 1992, the device shall reduce overall emissions of hydrogen halides and halogens, as defined in § 63.111, by 95 percent or shall reduce the outlet mass of total hydrogen halides and halogens to less than 0.45 kilograms per hour.

(2) A halogen reduction device, such as a scrubber or other technique, may be used to reduce the vent stream halogen atom mass emission rate to less than 0.45 kilogram per hour prior to any combustion control device, and thus make the vent stream nonhalogenated; the vent stream must comply with the requirements of paragraph (a)(1) or (2) of this section.

(d) Except as specified in paragraph (a)(4) of this section, the owner or operator of a Group 2 process vent having a flow rate greater than or equal to 0.005 standard cubic meter per minute, a HAP concentration greater than or equal to 50 parts per million by volume, and a TRE index value greater than 1.0 but less than or equal to 4.0 shall maintain a TRE index value greater than 1.0 and shall comply with the monitoring of recovery device parameters in § 63.114(b) or (c), the TRE index calculations of § 63.115 of this subpart, and the applicable reporting and recordkeeping provisions of §§ 63.117 and 63.118. Such owner or operator is not subject to any other provisions of §§ 63.114 through 63.118.

(e) Except as specified in paragraph (a)(4) of this section, the owner or operator of a Group 2 process vent with a TRE index value greater than 4.0 shall maintain a TRE index value greater than 4.0, comply with the provisions for calculation of a TRE index value in § 63.115 and the reporting and recordkeeping provisions in §§ 63.117(b) and 63.118(c) and (h), and is not subject to monitoring or any other provisions of §§ 63.114 through 63.118.

(f) Except as specified in paragraph (l) of this section, the owner or operator of a Group 2 process vent with a flow rate less than 0.005 standard cubic meter per minute shall maintain a flow rate less than 0.005 standard cubic meter per minute; comply with the Group determination procedures in § 63.115 (a), (b), and (e); and the reporting and recordkeeping requirements in §§ 63.117(c), 63.118(d), and 63.118(i); and is not subject to monitoring or any other provisions of §§ 63.114 through 63.118.

(g) Except as specified in paragraph (l) of this section, the owner or operator of a Group 2 process vent with a total organic HAP concentration less than 50 parts per million by volume shall maintain a total organic HAP concentration less than 50 parts per million by volume; comply with the Group determination procedures in § 63.115(a), (c), and (e); the reporting and recordkeeping requirements in §§ 63.117(d) and 63.118(e) and (j); and is not subject to monitoring or any other provisions of §§ 63.114 through 63.118.

(h) The owner or operator of a process vent complying with paragraph (a)(1) or (2) of this section is not required to perform the group determination described in § 63.115.

(i) *Off-site control or on-site control not owned or operated by the source.* This paragraph (i) applies to gas streams that have the characteristics specified in § 63.107(b) through (h) or meet the criteria specified in § 63.107(i); that are transferred for disposal to an on-site control device (or other compliance equipment) not owned or operated by the owner or operator of the source generating the gas stream, or to an off-site control device or other compliance equipment; and that have the characteristics (*e.g.,* flow rate, total organic HAP concentration, or TRE index value as applicable) of a Group 1 process vent, determined at the point of transfer.

(i) Comply with the provisions specified in § 63.114(d) for each gas stream prior to transfer.

(ii) Notify the transferee that the gas stream contains organic hazardous air pollutants that are to be treated in accordance with the provisions of this subpart. The notice shall be submitted to the transferee initially and whenever there is a change in the required control.

(2) The owner or operator may not transfer the gas stream unless the transferee has submitted to the EPA a written certification that the transferee will manage and treat any gas stream transferred under this paragraph (i) and received from a source subject to the requirements of this subpart in accordance with the requirements of either §§ 63.113 through 63.118, or § 63.102(b), or subpart D of this part if alternative emission limitations have been granted the transferor in accordance with those provisions. The certifying entity may revoke the written certification by sending a written statement to EPA and the owner or operator giving at least 90 days notice that the certifying entity is rescinding acceptance of responsibility for compliance with the regulatory provisions listed in this paragraph (i). Upon expiration of the notice period, the owner or operator may not transfer the gas stream to the transferee. Records retained by the transferee shall be retained in accordance with § 63.103(c).

(3) By providing this written certification to EPA, the certifying entity accepts responsibility for compliance with the regulatory provisions listed in paragraph (i)(2) of this section with respect to any transfer covered by the written certification. Failure to abide by any of those provisions with respect to such transfers may result in enforcement action by EPA against the certifying entity in accordance with the enforcement provisions applicable to violations of these provisions by owners or operators of sources.

(4) Written certifications and revocation statements to EPA from the transferees of such gas streams shall be signed by a responsible official of the certifying entity, provide the name and address of the certifying entity, and be sent to the appropriate EPA Regional Office at the addresses listed in § 63.13. Such written certifications are not transferable by the transferee.

(j) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(11), if the Group 1 or Group 2 process vent contains ethylene oxide such that it is considered to be in ethylene oxide service, as defined in § 63.101, then the owner or operator must comply with the requirements of paragraphs (j)(1) or (2) of this section in addition to all other applicable requirements specified elsewhere in this section.

(1) Reduce emissions of ethylene oxide by venting emissions through a closed vent system to a flare; or

(2) Reduce emissions of ethylene oxide by venting emissions through a closed vent system to a control device that reduces ethylene oxide by greater than or equal to 99.9 percent by weight,

or to a concentration less than 1 ppmv for each process vent or to less than 5 pounds per year for all combined process vents within the process. If a combustion device is used, the ethylene oxide concentration of 1 ppmv must be corrected to 3 percent oxygen.

(k) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), 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 must comply with the applicable requirements in paragraphs (k)(1) through (4) of this section for each maintenance vent. Any vent designated as a maintenance vent is only subject to the maintenance vent provisions in this paragraph (k) and the associated reporting and recordkeeping requirements in § 63.118(f)(9) and (m), respectively. The owner or operator does not need to designate a maintenance vent as a Group 1 or Group 2 process vent nor identify maintenance vents in a Notification of Compliance Status report.

(1) Prior to venting to the atmosphere, remove process liquids from the equipment as much as practical and depressurize the equipment to either: A flare meeting the requirements of § 63.108, as applicable, or using any combination of a non-flare combustion, recovery, and/or recapture device meeting the requirements in paragraph (a)(2) of this section until one of the following conditions, as applicable, is met.

(i) The concentration of the vapor in the equipment served by the maintenance vent is less than 10 percent of its lower explosive limit (LEL) and has an outlet concentration less than or equal to 20 ppmv hydrogen halide and halogen HAP.

(ii) If there is no ability to measure the concentration 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 pounds per square inch gauge (psig) or less. Upon opening the maintenance vent, active purging of the equipment cannot be used until the concentration of the vapors in the maintenance vent (or inside the equipment if the maintenance is a hatch or similar type of opening) is less than 10 percent of its LEL.

(iii) The equipment served by the maintenance vent contains less than 50 pounds of total volatile organic compounds (VOC).

(iv) If, after applying best practices to isolate and purge equipment served by a maintenance vent, none of the applicable criterion in paragraphs (k)(1)(i) through (iii) of this section can be met prior to installing or removing a blind flange or similar equipment blind, then the pressure in the equipment served by the maintenance vent must be reduced to 2 psig or less before installing or removing the equipment blind. During installation or removal of the equipment blind, active purging of the equipment may be used provided the equipment pressure at the location where purge gas is introduced remains at 2 psig or less.

(2) Except for maintenance vents complying with the alternative in paragraph (k)(1)(iii) of this section, the owner or operator must determine the concentration 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 (k)(1)(iii) of this section, the owner or operator must 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.

(4) In addition to complying with the requirements in paragraphs (k)(1) through (3) of this section, for process vents in ethylene oxide service, subject to the requirements of § 63.124 that are designated as maintenance vents, owners and operators may not release more than 1.0 tons of ethylene oxide from all maintenance vents combined per any consecutive 12-month period. The owner or operator must keep monthly records of the quantity in tons of ethylene oxide released from each maintenance vent and include a description of the method used to estimate this quantity.

(l) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), paragraphs (f) and (g) of this section no longer apply. Instead, the owner or operator of a Group 2 process vent with a total organic HAP mass flow rate less than 1.0 pound per hour shall maintain a total organic HAP mass flow rate less than 1.0 pound per hour; comply with the Group determination procedures in § 63.115(g); and the reporting and recordkeeping requirements in §§ 63.117(g) and 63.118(n); and is not subject to monitoring or any other provisions of §§ 63.114 through 63.118.

■ 58. Revise and republish § 63.114 to read as follows:

§ 63.114 Process vent provisions—monitoring requirements.

(a) Each owner or operator of a process vent that uses a combustion device to comply with the requirements in § 63.113(a)(1), (2), or (5), or that uses a recovery device or recapture device to comply with the requirements in § 63.113(a)(2), shall install monitoring equipment specified in paragraph (a)(1), (2), (3), (4), (5), or (6) of this section, depending on the type of 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 would reasonably be expected to monitor accurately.

(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, except as specified in § 63.108(a), the following monitoring equipment is required: A device (including but not limited to a thermocouple, ultra-violet beam sensor, or infrared sensor) capable of continuously detecting the presence of a pilot flame.

(3) Where a boiler or process heater of less than 44 megawatts design heat input capacity is used, the following monitoring equipment is required: a temperature monitoring device in the firebox equipped with a continuous recorder. This requirement does not apply to gas streams that are introduced with primary fuel or are used as the primary fuel.

(4) Where a scrubber is used with an incinerator, boiler, or process heater in the case of halogenated vent streams, the following monitoring equipment is required for the scrubber.

(i) A pH monitoring device equipped with a continuous recorder shall be installed to monitor the pH of the scrubber effluent.

(ii) A flow meter equipped with a continuous recorder shall be located at the scrubber influent for liquid flow. Gas flow rate shall be determined using one of the procedures specified in paragraphs (a)(4)(ii)(A) through (C) of this section.

(A) The owner or operator may determine gas flow rate using the design blower capacity, with appropriate adjustments for pressure drop.

(B) If the scrubber is subject to rules in 40 CFR parts 264 through 266 that have required a determination of the liquid to gas (L/G) ratio prior to the applicable compliance date for this subpart specified in § 63.100(k), the owner or operator may determine gas flow rate by the method that had been utilized to comply with those rules. A determination that was conducted prior to the compliance date for this subpart may be utilized to comply with this subpart if it is still representative.

(C) The owner or operator may prepare and implement a gas flow rate determination plan that documents an appropriate method which will be used to determine the gas flow rate. The plan shall require determination of gas flow rate by a method which will at least provide a value for either a representative or the highest gas flow rate anticipated in the scrubber during representative operating conditions other than startups, shutdowns, or malfunctions. The plan shall include a description of the methodology to be followed and an explanation of how the selected methodology will reliably determine the gas flow rate, and a description of the records that will be maintained to document the determination of gas flow rate. The owner or operator shall maintain the plan as specified in § 63.103(c). For each source as defined in § 63.101, on and after July 15, 2027, the phrase ‘‘other than startups, shutdowns, or malfunctions’’ in this paragraph no longer applies.

(5) Where a recovery device or recapture device is used to comply with the requirements of § 63.113(a)(2) or (5), the owner or operator shall utilize the appropriate monitoring device identified in paragraph (a)(5)(i), (ii), (iii), (iv), or (v) of this section. All monitoring equipment shall be installed, calibrated, and maintained according to the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment would reasonably be expected to monitor accurately.

(i) Install either an organic monitoring device equipped with a continuous recorder;

(ii) Where an absorber is the final recovery device in the recovery system, a scrubbing liquid temperature monitoring device and a specific gravity monitoring device, each equipped with a continuous recorder shall be used;

(iii) Where a condenser is the final recovery device in the recovery system, a condenser exit (product side) temperature monitoring device equipped with a continuous recorder shall be used;

(iv) Except as specified in paragraph (a)(5)(v) of this section, where a carbon adsorber is the final recovery device in the recovery system, an integrating regeneration stream flow monitoring device having an accuracy of ±10 percent or better, capable of recording the total regeneration stream mass or volumetric flow for each regeneration cycle; and a carbon bed temperature monitoring device, capable of recording the carbon bed temperature after each regeneration and within 15 minutes of completing any cooling cycle shall be used.

(v) Beginning no later than the compliance dates specified in § 63.100(k)(10), if the owner or operator vents emissions through a closed vent system to an adsorber(s) that cannot be regenerated or a regenerative adsorber(s) that is regenerated offsite, then the owner or operator must install a system of two or more adsorber units in series and comply with the requirements specified in paragraphs (a)(5)(v)(A) through (C) of this section.

(A) Conduct an initial performance test or design evaluation of the adsorber and establish the breakthrough limit and adsorber bed life.

(B) Monitor the HAP or total organic compound (TOC) concentration through a sample port at the outlet of the first adsorber bed in series according to the schedule in paragraph (a)(5)(v)(C)(*2*) of this section. The owner or operator must measure the concentration of HAP or TOC using either a portable analyzer, in accordance with Method 21 of appendix A–7 to part 60 of this chapter using methane, propane, isobutylene, or the primary HAP being controlled as the calibration gas or Method 25A of part 60, appendix A–7, using methane, propane, or the primary HAP being controlled as the calibration gas.

(C) Comply with paragraph (a)(5)(v)(C)(*1*) of this section and comply with the monitoring frequency according to paragraph (a)(5)(v)(C)(*2*) of this section.

(*1*) The first adsorber in series must be replaced immediately when breakthrough, as defined in § 63.101, is detected between the first and second adsorber. The original second adsorber (or a fresh canister) will become the new first adsorber and a fresh adsorber will become the second adsorber. For purposes of this paragraph, ‘‘immediately’’ means within 8 hours of the detection of a breakthrough for adsorbers of 55 gallons or less, and within 24 hours of the detection of a breakthrough for adsorbers greater than 55 gallons. The owner or operator must monitor at the outlet of the first adsorber within 3 days of replacement to confirm it is performing properly.

(*2*) Based on the adsorber bed life established according to paragraph (a)(5)(v)(A) of this section and the date the adsorbent was last replaced, conduct monitoring to detect breakthrough at least monthly if the adsorbent has more than 2 months of life remaining, at least weekly if the adsorbent has between 2 months and 2 weeks of life remaining, and at least daily if the adsorbent has 2 weeks or less of life remaining.

(6) Where sorbent injection is used, the following monitoring equipment is required for the sorbent injection system:

(i) A sorbent injection rate monitoring device (*e.g.,* weigh belt, weigh hopper, hopper flow measurement device) installed in a position that provides a representative measurement equipped with a continuous recorder to monitor the sorbent injection rate; and

(ii) A flow measurement device equipped with a continuous recorder to monitor the carrier gas flow rate.

(b) Except as specified in § 63.113(a)(4), each owner or operator of a process vent with a TRE index value greater than 1.0 as specified under § 63.113(a)(3) or (d) that uses one or more recovery devices shall install either an organic monitoring device equipped with a continuous recorder or the monitoring equipment specified in paragraph (b)(1), (2), or (3) of this section, depending on the type of recovery device used. All monitoring equipment shall be installed, calibrated, and maintained according to the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment would reasonably be expected to monitor accurately. Monitoring is not required for process vents with TRE index values greater than 4.0 as specified in § 63.113(e).

(1) Where an absorber is the final recovery device in the recovery system, a scrubbing liquid temperature monitoring device and a specific gravity monitoring device, each equipped with a continuous recorder shall be used;

(2) Where a condenser is the final recovery device in the recovery system, a condenser exit (product side) temperature monitoring device equipped with a continuous recorder shall be used;

(3) Where a carbon adsorber is the final recovery device in the recovery system, an integrating regeneration stream flow monitoring device having an accuracy of ±10 percent or better, capable of recording the total regeneration stream mass or volumetric flow for each regeneration cycle; and a carbon bed temperature monitoring device, capable of recording the carbon bed temperature after each regeneration and within 15 minutes of completing any cooling cycle shall be used.

(c) An owner or operator of a process vent may request approval to monitor parameters other than those listed in paragraph (a) or (b) of this section. The request shall be submitted according to the procedures specified in § 63.151(f) or § 63.152(e) of this subpart. Approval shall be requested if the owner or operator:

(1) Uses a combustion device other than an incinerator, boiler, process heater, or flare; or

(2) Except as specified in § 63.113(a)(4), maintains a TRE greater than 1.0 but less than or equal to 4.0 without a recovery device or with a recovery device other than the recovery devices listed in paragraphs (a) and (b) of this section; or

(3) Uses one of the combustion or recovery or recapture devices listed in paragraphs (a) and (b) of this section, but seeks to monitor a parameter other than those specified in paragraphs (a) and (b) of this section.

(d) The owner or operator of a process vent shall comply with paragraphs (d)(1) or (2) and (d)(3) of this section for any bypass line between the origin of the gas stream (*i.e.,* at an air oxidation reactor, distillation unit, or reactor as identified in § 63.107(b)) and the point where the gas stream reaches the process vent, as described in § 63.107, that could divert the gas stream directly to the atmosphere. Except as specified in paragraph (d)(3)(ii) of this section, equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and pressure relief valves needed for safety purposes are not subject to this paragraph (d).

(1) Properly install, maintain, and operate a flow indicator that takes a reading at least once every 15 minutes. Records shall be generated as specified in § 63.118(a)(3). The flow indicator shall be installed at the entrance to any bypass line that could divert the gas stream 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 the gas stream is not diverted through the bypass line

(3) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10):

(i) The use of a bypass line at any time on a closed vent system to divert emissions (subject to the emission standards in § 63.112) to the atmosphere or to a control device not meeting the requirements specified in this subpart is an emissions standards violation.

(ii) The last sentence in paragraph (d) of this section no longer applies. Instead, the exemptions specified in paragraphs (d)(3)(ii)(A) and (B) of this section apply.

(A) Except for pressure relief devices subject to § 63.165(e)(4) of subpart H of this part, equipment such as low leg drains and equipment subject to the requirements of subpart H of this part are not subject to this paragraph (d) of this section.

(B) Open-ended valves or lines that use a cap, blind flange, plug, or second valve and follow the requirements specified in § 60.482–6(a)(2), (b), and (c) of this chapter or follow requirements codified in another regulation that are the same as § 60.482–6(a)(2), (b), and (c) are not subject to this paragraph (d).

(e) The owner or operator shall establish a range that indicates proper operation of the control or recovery device for each parameter monitored under paragraphs (a), (b), and (c) of this section based on the results of the most recent performance test. In order to establish the range, the information required in § 63.152(b) shall be submitted in the Notification of Compliance Status or the operating permit application or amendment. The range may be based upon a prior performance test conducted for determining compliance with a regulation promulgated by the EPA, and the owner or operator is not required to conduct an initial performance test under § 63.116, if the prior performance test was conducted using the same methods specified in § 63.116 and either no process changes have been made since the test, or the owner or operator can demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process changes. Subsequent performance tests must be conducted according to § 63.103(b)(1).

■ 59. Amend § 63.115 by revising paragraphs (a) introductory text, (b) introductory text, (c) introductory text, (d) introductory text, (e) introductory text and (f) introductory text and adding paragraph (g) to read as follows:

§ 63.115 Process vent provisions—methods and procedures for process vent group determination.

(a) For purposes of determining vent stream flow rate, total organic HAP or total organic carbon concentration or TRE index value as applicable, as specified under paragraph (b), (c), or (d) of this section, the sampling site shall be after the last recovery device (if any recovery devices are present) but prior to the inlet of any control device that is present and prior to release to the atmosphere.

* * * * *

(b) Except as specified in paragraph (g) of this section, to demonstrate that a vent stream flow rate is less than 0.005 standard cubic meter per minute in accordance with the Group 2 process vent definition of this subpart, the owner or operator shall measure flow rate by the following procedures:

* * * * *

(c) Except as specified in paragraph (g) of this section, each owner or operator seeking to demonstrate that a vent stream has an organic HAP concentration below 50 parts per million by volume in accordance with the Group 2 process vent definition of this subpart shall measure either total organic HAP or TOC concentration using the following procedures:

* * * * *

(d) Except as specified in § 63.113(a)(4), to determine the TRE index value, the owner or operator shall conduct a TRE determination and calculate the TRE index value according to the procedures in paragraph (d)(1) or (2) of this section and the TRE equation in paragraph (d)(3) of this section.

* * * * *

(e) Except as specified in § 63.113(a)(4), the owner or operator of a Group 2 process vent shall recalculate the TRE index value, flow, or organic hazardous air pollutants concentration for each process vent, as necessary to determine whether the vent is Group 1 or Group 2, whenever process changes are made that could reasonably be expected to change the vent to a Group 1 vent. Examples of process changes include, but are not limited to, changes in production capacity, production rate, feedstock type, 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 TRE calculation was based.

* * * * *

(f) Except as specified in § 63.113(a)(4), notwithstanding any other provisions of this subpart, in any case where a process vent includes one or more gas streams that are not from a source subject to this subpart (hereafter called ''non-HON streams'' for purposes of this paragraph), and one or more gas streams that meet the criteria in § 63.107(b) through (h) or the criteria in § 63.107(i) (hereafter called ''HON streams'' for purposes of this paragraph), the owner or operator may elect to comply with paragraphs (f)(1) through (3) of this section.

* * * * *

(g) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), paragraphs (b) and (c) of this section no longer apply. Instead, to demonstrate that a vent stream total organic HAP mass flow rate is less than 1.0 pound per hour in accordance with the Group 2 process vent definition of this subpart, the owner or operator must use the following procedures:

(1) The sampling site must be selected as specified in paragraph (a) of this section.

(2) Method 18 or Method 25A of appendices A–6 and A–7 to 40 CFR part 60 of this chapter, respectively, or Method 320 of appendix A to this part must be used to measure concentration. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18 or Method 320, if the target compounds are all known and are all listed in section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method.

(3) Where Method 18 of appendix A–6 to part 60 of this chapter, Method 320 of appendix A to this part, or ASTM D6420–18 is used, the following procedures must be used to calculate the total organic HAP mass flow rate:

(i) The minimum sampling time for each run must be 1 hour in which either an integrated sample or four grab samples must be taken. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15 minute intervals during the run.

(ii) The mass rate of total organic HAP for each run must be computed using the following equation:

Equation 6 to Paragraph (g)(3)(ii)

$$E_{HAP} = KQ\sum_{j=1}^{n} C_j M_j$$

Where:

E_{HAP} = Emission rate of total organic HAP, lb/hr.

K = 1.675×10^{-7} (parts per million)$^{-1}$ (lb-mole per standard cubic feet) (minutes per hour), where standard temperature is 68 °F (20 °C).

Q = Flowrate of gas stream, dry standard cubic feet per minute), where standard temperature is 68 °F (20 °C), determined using Method 2, 2A, 2C, or 2D of 40 CFR part 60, appendix A, as appropriate. The flowrate may be based solely on an engineering assessment if measurements cannot be made with EPA reference methods.

C_j = Concentration of organic compound j in the gas stream as measured by Method 18 of appendix A–6 to 40 CFR part 60, Method 320 of appendix A to this part, or ASTM D6420–18 (incorporated by reference, see § 63.14), ppmv dry basis. The concentration may be based solely on an engineering assessment if measurements cannot be made with EPA reference methods.

M_i = Molecular weight of organic compound j, lb/lb-mole.

j = Individual organic HAP compound in the gas stream. The list of organic HAPs is provided in table 2 of subpart F of this part.

n = Number of organic HAP compounds j in the gas stream.

(iii) The owner or operator must demonstrate that the emission rate of total organic HAP is less than 1.0 pound per hour for the vent stream to be considered a Group 2 process vent.

(4) Where Method 25A of appendix A–7 to part 60 of this chapter is used, the following procedures must be used to calculate parts per million by volume TOC concentration:

(i) Method 25A of appendix A–7 to part 60 of this chapter must be used only if a single organic HAP compound is greater than 50 percent of total organic HAP, by volume, in the vent stream.

(A) This organic HAP must be used as the calibration gas for Method 25A of appendix A–7 to part 60 of this chapter.

(B) Use of Method 25A of appendix A–7 to part 60 of this chapter 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.

(ii) The span value for Method 25A of appendix A–7 to part 60 of this chapter must be equal to approximately twice the expected concentration of TOC in the gas stream.

(iii) The minimum sampling time for each run must be 1 hour. The results must be corrected to a dry basis. You must use Method 4 of appendix A–3 to part 60 of this chapter to convert the Method 25A results to a dry basis.

(iv) The mass rate of TOC for each run must be computed using the following equation:

Equation 7 to Paragraph (g)(4)(iv)

$$E_{TOC} = KCMQ$$

Where:

E_{TOC} = Emission rate of TOC, lb/hr.

K = 1.675×10^{-7} (parts per million)$^{-1}$ (lb-mole per standard cubic feet) (minutes per hour), where standard temperature is 68 °F (20 °C).

C = Concentration of TOC in the gas stream as measured by Method 25A of appendix A to part 60 of this chapter ppmv dry basis. The concentration may be based solely on an engineering assessment if measurements cannot be made with EPA reference methods.

M = Molecular weight of the organic HAP used as the calibration gas, lb/lb-mole.

Q = Flowrate of gas stream, dry standard cubic feet per minute), where standard temperature is 68 °F (20 °C), determined using Method 2, 2A, 2C, or 2D of appendix A–1 to part 60 of this chapter, as appropriate. The flowrate may be based solely on an engineering assessment if measurements cannot be made with EPA reference methods.

(v) The owner or operator must demonstrate that the emission rate of TOC is less than 1.0 pound per hour for the vent stream to be considered a Group 2 process vent.

(5) The requirements specified in paragraphs (g)(1) through (4) of this section for an initial measurement or initial performance test do not apply if the conditions specified in paragraphs (g)(5)(i) through (iv) of this section are met for a previously conducted measurement or performance test.

(i) No changes have been made to the process since the time of the measurement or performance test;

(ii) The operating conditions and test methods used during measurement or performance test conform to the requirements in paragraphs (g)(1) through (4) of this section;

(iii) The control device and process parameter values established during the previously conducted measurement or performance test are used to demonstrate continuous compliance with the related requirements of this subpart, if applicable; and

(iv) The previously conducted measurement or performance test was completed within the last 60 months.

■ 60. Amend § 63.116 by:

■ a. Revising paragraphs (a) introductory text, (b)(3) through (5), (c) introductory text, (c)(3) introductory text, (c)(3)(iii)(A), (c)(4) introductory text, (c)(4)(ii)(B), and (d) introductory text; and

■ b. Adding paragraphs (f) through (h).

The revisions and additions read as follows:

§ 63.116 Process vent provisions—performance test methods and procedures to determine compliance.

(a) When a flare is used to comply with § 63.113(a)(1), the owner or operator shall comply with paragraphs (a)(1) through (3) of this section except as specified in § 63.108(a). The owner or operator is not required to conduct a performance test to determine percent emission reduction or outlet organic HAP or TOC concentration.

* * * * *

(b) * * *

(3) A control device for which a performance test was conducted for determining compliance with a regulation promulgated by the EPA and the test was conducted using the same methods specified in this section and either no process changes have been made since the test, or the owner or operator can demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process changes is not required to conduct an initial performance test. Subsequent performance tests must be conducted according to § 63.103(b)(1).

(4) A boiler or process heater burning hazardous waste for which the owner or operator:

(i) Has been issued a final permit under part 270 of this chapter and complies with the requirements of part 266, subpart H, of this chapter;

(ii) Has certified compliance with the interim status requirements of part 266, subpart H, of this chapter;

(iii) Meets the requirement specified in paragraph (b)(4)(v) of this section, and has submitted a Notification of Compliance under § 63.1207(j) and complies with the requirements of subpart EEE of this part; or

(iv) Meets the requirement specified in paragraph (b)(4)(v) of this section, complies with subpart EEE of this part, and will submit a Notification of Compliance under § 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

(v) The owner and operator may not waive performance testing pursuant to § 63.1207(d)(4) and each performance test required by § 63.1207(d) must show compliance with the dioxins and furans emission limit specified in § 63.113(a)(5).

(5) A hazardous waste incinerator for which the owner or operator:

(i) Has been issued a final permit under 40 CFR part 270 and complies with the requirements of part 264, subpart O, of this chapter;

(ii) Has certified compliance with the interim status requirements of part 265, subpart O, of this chapter.

(iii) Meets the requirement specified in paragraph (b)(5)(v) of this section, and has submitted a Notification of Compliance under § 63.1207(j) and complies with the requirements subpart EEE of this part; or

(iv) Meets the requirement specified in paragraph (b)(5)(v) of this section, complies with the requirements subpart EEE of this part, and will submit a Notification of Compliance under § 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

(v) The owner and operator may not waive performance testing pursuant to § 63.1207(d)(4) and each performance test required by § 63.1207(d) must show compliance with the dioxins and furans emission limit specified in § 63.113(a)(5).

(c) Except as provided in paragraphs (a) and (b) of this section, an owner or operator using a control device to comply with the organic HAP concentration limit or percent reduction efficiency requirements in § 63.113(a)(2) of this subpart shall conduct performance tests using the procedures in paragraphs (c)(1) through (4) of this section according to the schedule in § 63.103(b)(1) of subpart F of this part. The organic HAP concentration and percent reduction may be measured as either total organic HAP or as TOC minus methane and ethane according to the procedures specified.

* * * * *

(3) To determine compliance with the 20 parts per million by volume total organic HAP limit in § 63.113(a)(2) of this subpart, the owner or operator shall use Method 18 of appendix A–6 to part 60 of this chapter to measure either TOC minus methane and ethane or total organic HAP. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method. Alternatively, any other method or data that has been validated according to the applicable procedures in Method 301 of appendix A of this part, may be used. The following procedures shall be used to calculate parts per million by volume concentration, corrected to 3 percent oxygen:

* * * * *

(iii) * * *

(A) Method 3A of appendix A–2 to part 60 of this chapter or the manual method in ANSI/ASME PTC 19.10–1981 (incorporated by reference, see § 63.14) shall be used to determine the oxygen concentration (%O2d). The samples shall be taken during the same time that the TOC (minus methane or ethane) or total organic HAP samples are taken.

* * * * *

(4) To determine compliance with the 98 percent reduction requirement of § 63.113(a)(2), the owner or operator shall use Method 18 of appendix A–6 to part 60 of this chapter; alternatively, any other method or data that has been validated according to the applicable procedures in Method 301 of appendix A to this part may be used. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for

methane and ethane; and ASTM D6420–18 may not be used as a total VOC method. The following procedures shall be used to calculate percent reduction efficiency:

* * * * *

(ii) * * *

(B) Where the mass rate of TOC is being calculated, all organic compounds (minus methane and ethane) measured by Method 18 of appendix A–6 to part 60 of this chapter or ASTM D6420–18 (incorporated by reference, see § 63.14) are summed using the equation in paragraph (c)(4)(ii)(A) of this section.

* * * * *

(d) An owner or operator using a combustion device followed by a scrubber or other halogen reduction device to control halogenated vent streams in compliance with § 63.113(c)(1) shall conduct performance tests to determine compliance with the control efficiency or emission limits for hydrogen halides and halogens according to the schedule in § 63.103(b)(1).

* * * * *

(f) To demonstrate compliance with the emission limits and work practice standards specified in § 63.113(j) for process vents in ethylene oxide service, owners and operators must meet the requirements specified in § 63.124.

(g) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), an owner or operator using a recapture device to comply with the organic HAP concentration limit or percent reduction efficiency requirements in § 63.113(a)(2) shall conduct a performance test using the same procedures specified in paragraph (c) of this section, except the term ‘‘recapture device’’ is substituted for ‘‘control device.’’

(h) To demonstrate compliance with the dioxins and furans emission limit specified in § 63.113(a)(5), owners and operators must conduct performance tests using the procedures in paragraphs (h)(1) through (6) of this section according to the schedule in § 63.103(b)(1).

(1) The performance test must consist of three test runs. Collect at least 3 dry standard cubic meters of gas per test run.

(2) Use Method 1 or 1A of appendix A–1 to 40 CFR part 60 to select the sampling sites at the sampling location. The sampling location must be at the outlet of the final control device.

(3) Determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of appendix A–1 to part 60 of this chapter.

(4) Use Method 4 of appendix A–3 to part 60 of this chapter to convert the volumetric flowrate to a dry basis.

(5) Measure the concentration of each tetra- through octa-chlorinated dioxin and furan congener emitted using Method 23 of appendix A–7 to part 60 of this chapter.

(i) For each dioxin and furan congener, multiply the congener concentration by its corresponding toxic equivalency factor specified in table 38 to this subpart. For determination of toxic equivalency, zero may be used for congeners with a concentration less than the estimated detection limit (EDL). For congeners with estimated maximum pollutant concentration (EMPC) results, if the value is less than the EDL, zero may be used. Otherwise, the EMPC value must be used in the calculation of toxic equivalency.

(ii) Sum the products calculated in accordance with paragraph (h)(5)(i) of this section to obtain the total concentration of dioxins and furans emitted in terms of toxic equivalency.

(6) The concentration of dioxins and furans shall be corrected to 3 percent oxygen. Use Method 3A of 40 CFR part 60, appendix A, or the manual method in ANSI/ASME PTC 19.10–1981 (incorporated by reference, see § 63.14) to determine the oxygen concentration (%O2d). The oxygen concentration must be determined concurrently with Method 23 of appendix A–7 to part 60 of this chapter. The concentration corrected to 3 percent oxygen (Cc) shall be computed using the following equation:

$$C_c = C_m\left(\frac{17.9}{20.9-\%O_{2d}}\right)$$

Where:

C_c = Concentration of dioxins and furans corrected to 3 percent oxygen, dry basis, nanograms per standard cubic meter.

C_m = Concentration of dioxins and furans, dry basis, nanograms per standard cubic meter.

%O2d = Concentration of oxygen, dry basis, percent by volume.

■ 61. Revise and republish § 63.117 to read as follows:

§ 63.117 Process vent provisions—reporting and recordkeeping requirements for group and TRE determinations and performance tests.

(a) Except as specified in § 63.113(a)(4), each owner or operator subject to the control provisions for Group 1 process vents in § 63.113(a) or the provisions for Group 2 process vents with a TRE index value greater than 1.0 but less than or equal to 4.0 in § 63.113(d) shall:

(1) Keep an up-to-date, readily accessible record of the data specified in paragraphs (a)(4) through (10) of this section, as applicable, and

(2) Include the data in paragraphs (a)(4) through (10) of this section in the Notification of Compliance Status report as specified in § 63.152(b) of this subpart.

(3) Except as specified in § 63.113(a)(4), if any subsequent TRE determinations or performance tests are conducted after the Notification of Compliance Status has been submitted, report the data in paragraphs (a)(4) through (a)(10) of this section in the next Periodic Report as specified in § 63.152(c).

(4) Record and report the following when using a combustion device to achieve a 98 weight percent reduction in organic HAP or an organic HAP concentration of 20 parts per million by volume, as specified in § 63.113(a)(2):

(i) The parameter monitoring results for incinerators, catalytic incinerators, boilers or process heaters specified in table 3 of this subpart, and averaged over the same time period of the performance testing.

(ii) For an incinerator, the percent reduction of organic HAP or TOC achieved by the incinerator determined as specified in § 63.116(c), or the concentration of organic HAP or TOC (parts per million by volume, by compound) determined as specified in § 63.116(c) at the outlet of the incinerator on a dry basis corrected to 3 percent oxygen.

(iii) For a boiler or process heater, a description of the location at which the vent stream is introduced into the boiler or process heater.

(iv) For a boiler or process heater with a design heat input capacity of less than 44 megawatts and where the vent stream is introduced with combustion air or used as a secondary fuel and is not mixed with the primary fuel, the percent reduction of organic HAP or

TOC, or the concentration of organic HAP or TOC (parts per million by volume, by compound) determined as specified in § 63.116(c) at the outlet of the combustion device on a dry basis corrected to 3 percent oxygen.

(5) Except as specified in § 63.108)(a), record and report the following when using a flare to comply with § 63.113(a)(1):

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

(ii) All visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the compliance determination required by § 63.116(a); and

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

(6) Record and report the following when using a scrubber following a combustion device to control a halogenated vent stream:

(i) The percent reduction or scrubber outlet mass emission rate of total hydrogen halides and halogens as specified in § 63.116(d);

(ii) The pH of the scrubber effluent; and

(iii) The scrubber liquid to gas ratio.

(7) Except as specified in § 63.113(a)(4), record and report the following when achieving and maintaining a TRE index value greater than 1.0 but less than 4.0 as specified in § 63.113(a)(3) or (d):

(i) The parameter monitoring results for absorbers, condensers, or carbon adsorbers, as specified in table 4 to this subpart, and averaged over the same time period of the measurements of vent stream flow rate and concentration used in the TRE determination (both measured while the vent stream is normally routed and constituted), and

(ii) The measurements and calculations performed to determine the TRE index value of the vent stream.

(8) Record and report the halogen concentration in the vent stream determined according to the procedures specified in § 63.115(d)(2)(v).

(9) When using a recapture device to achieve a 98 weight percent reduction in organic HAP or an organic HAP concentration of 20 parts per million by volume, as specified in § 63.113(a)(2), record and report the parameter monitoring results for absorbers, condensers, or carbon adsorbers, as specified in table 3 of this subpart, and averaged over the same time period of the performance testing.

(10) Record and report the following when using a control device, recapture device, or recovery device to meet the dioxins and furans emissions limit.

(i) The parameter monitoring results, as specified in table 3 of this subpart, for the applicable device and averaged over the same time period of the performance testing.

(ii) The dioxins and furans concentration on a toxic equivalency basis (nanograms per standard cubic meter on a dry basis corrected to 3 percent oxygen) determined as specified in § 63.116(h).

(b) Except as specified in § 63.113(a)(4), the owner or operator of a Group 2 process vent with a TRE index greater than 4.0 as specified in § 63.113(e), shall maintain records and submit as part of the Notification of Compliance Status specified in § 63.152, measurements, engineering assessments, and calculations performed to determine the TRE index value of the vent stream. Documentation of engineering assessments shall include all data, assumptions, and procedures used for the engineering assessments, as specified in § 63.115(d)(1).

(c) Except as specified in paragraph (g) of this section, each owner or operator who elects to demonstrate that a process vent is a Group 2 process vent based on a flow rate less than 0.005 standard cubic meter per minute must submit to the Administrator the flow rate measurement using methods and procedures specified in § 63.115(a) and (b) with the Notification of Compliance Status specified in § 63.152.

(d) Except as specified in paragraph (g) of this section, each owner or operator who elects to demonstrate that a process vent is a Group 2 process vent based on organic HAP or TOC concentration less than 50 parts per million by volume must submit to the Administrator an organic HAP or TOC concentration measurement using the methods and procedures specified in § 63.115(a) and (c) with the Notification of Compliance Status specified in § 63.152.

(e) If an owner or operator uses a control or recovery device other than those listed in tables 3 and 4 to this subpart or requests approval to monitor a parameter other than those specified in tables 3 and 4 to this subpart, the owner or operator shall submit a description of planned reporting and recordkeeping procedures as required under § 63.151(f) or § 63.152(e). The Administrator will specify appropriate reporting and recordkeeping requirements as part of the review of the permit application or by other appropriate means.

(f) For each parameter monitored according to tables 3 or 4 to this subpart or paragraph (e) of this section, the owner or operator shall establish a range for the parameter that indicates proper operation of the control or recovery device. In order to establish the range, the information required in § 63.152(b) shall be submitted in the Notification of Compliance Status or the operating permit application or amendment.

(g) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), paragraphs (c) and (d) of this section no longer apply. Instead, each owner or operator demonstrating that a process vent is a Group 2 process vent based on total organic HAP mass flow rate less than 1.0 pound per hour must submit to the Administrator a total organic HAP measurement using the methods and procedures specified in § 63.115(g) with the Notification of Compliance Status specified in § 63.152.

■ 62. Revise and republish § 63.118 to read as follows:

§ 63.118 Process vent provisions—periodic reporting and recordkeeping requirements.

(a) Each owner or operator using a control device to comply with § 63.113(a)(1), (2), or (5) shall keep the following records up-to-date and readily accessible:

(1) Continuous records of the equipment operating parameters specified to be monitored under § 63.114(a) to this subpart and listed in table 3 to this subpart or specified by the Administrator in accordance with § 63.114(c) and § 63.117(e). For flares, the hourly records and records of pilot flame outages specified in table 3 to this subpart shall be maintained in place of continuous records.

(2) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.152(f). For flares complying with § 63.11(b), records of the times and duration of all periods during which all pilot flames are absent shall be kept rather than daily averages. For flares complying with § 63.108, the owner or operator must comply with the recordkeeping requirements specified therein.

(3) Hourly records of whether the flow indicator specified under § 63.114(d)(1) was operating and whether a diversion was detected at any time during the hour, as well as records of the times and durations of all periods when the gas stream is diverted to the atmosphere or the monitor is not operating.

(4) Where a seal mechanism is used to comply with § 63.114(d)(2), hourly records of flow are not required. In such cases, the owner or operator shall record that the monthly visual inspection of

the seals or closure mechanism has been done, and shall record the duration of all periods when the seal mechanism is broken, the bypass line valve position has changed, or the key for a lock-and-key type lock has been checked out, and records of any car-seal that has broken.

(5) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), the owner or operator must comply with this paragraph in addition to the requirements in paragraphs (a)(1) through (4) of this section. For each flow event from a bypass line subject to the requirements in § 63.114(d), the owner or operator must maintain records sufficient to determine whether or not the detected flow included flow requiring control. For each flow event from a bypass line requiring control that is released either directly to the atmosphere or to a control device not meeting the requirements in this subpart, the owner or operator must 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.

(b) Except as specified in § 63.113(a)(4), each owner or operator using a recovery device or other means to achieve and maintain a TRE index value greater than 1.0 but less than 4.0 as specified in § 63.113(a)(3) or (d) shall keep the following records up-to-date and readily accessible:

(1) Continuous records of the equipment operating parameters specified to be monitored under § 63.114(b) to this subpart and listed in table 4 to this subpart or specified by the Administrator in accordance with § 63.114(c) and § 63.114(e) and

(2) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.152(f). If carbon adsorber regeneration stream flow and carbon bed regeneration temperature are monitored, the records specified in table 4 to this subpart shall be kept instead of the daily averages.

(c) Except as specified in § 63.113(a)(4), each owner or operator subject to the provisions of this subpart and who elects to demonstrate compliance with the TRE index value greater than 4.0 under § 63.113(e) or greater than 1.0 under § 63.113(a)(3) or (d) shall keep up-to-date, readily accessible records of:

(1) Any process changes as defined in § 63.115(e); and

(2) Any recalculation of the TRE index value pursuant to § 63.115(e).

(d) Except as specified in paragraph (n) of this section, each owner or operator who elects to comply by maintaining a flow rate less than 0.005 standard cubic meter per minute under § 63.113(f), shall keep up-to-date, readily accessible records of:

(1) Any process changes as defined in § 63.115(e) that increase the vent stream flow rate,

(2) Any recalculation or measurement of the flow rate pursuant to § 63.115(e), and

(3) Except as specified in § 63.113(a)(4), if the flow rate increases to 0.005 standard cubic meter per minute or greater as a result of the process change, the TRE determination performed according to the procedures of § 63.115(d).

(e) Except as specified in paragraph (n) of this section, each owner or operator who elects to comply by maintaining an organic HAP concentration less than 50 parts per million by volume organic HAP concentration under § 63.113(g) shall keep up-to-date, readily accessible records of:

(1) Any process changes as defined in § 63.115(e) that increase the organic HAP concentration of the vent stream,

(2) Any recalculation or measurement of the concentration pursuant to § 63.115(e), and

(3) Except as specified in § 63.113(a)(4), if the organic HAP concentration increases to 50 parts per million by volume or greater as a result of the process change, the TRE determination performed according to the procedures of § 63.115(d).

(f) Each owner or operator who elects to comply with the requirements of § 63.113 of this subpart shall submit to the Administrator Periodic Reports of the following recorded information according to the schedule in § 63.152.

(1) Reports of daily average values of monitored parameters for all operating days when the daily average values recorded under paragraphs (a) and (b) of this section were outside the ranges established in the Notification of Compliance Status or operating permit, including the date that the parameter was outside the range.

(2) For Group 1 points, reports of the duration (in hours) of periods when monitoring data is not collected for each excursion caused by insufficient monitoring data as defined in § 63.152(c)(2)(ii)(A), including the start date of such periods.

(3) Reports of the times and durations of all periods recorded under paragraph (a)(3) of this section when the gas stream is diverted to the atmosphere through a bypass line and if applicable, the information in paragraph (f)(7) of this section. Include the start date, start time and duration in hours of each period.

(4) Reports of all periods recorded under paragraph (a)(4) of this section in which the seal mechanism is broken, the bypass line valve position has changed, or the key to unlock the bypass line valve was checked out and if applicable, the information in paragraph (f)(7) of this section. Include the start date, start time and duration in hours of each period.

(5) Except as specified in paragraph (a) of § 63.108, reports of the times and durations of all periods recorded under paragraph (a)(2) of this section in which all pilot flames of a flare were absent.

(6) Reports of all carbon bed regeneration cycles during which the parameters recorded under paragraph (b)(2)(v) of this section were outside the ranges established in the Notification of Compliance Status or operating permit. Include the identification of the carbon bed, the monitored parameter that was outside the established range, and the start date, start time and duration in hours of the regeneration cycle.

(7) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), the owner or operator must comply with this paragraph in addition to the requirements in paragraphs (f)(3) and (4) of this section. For bypass lines subject to the requirements in § 63.114(d), the Periodic Report must include the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of organic HAP in the gas in parts per million by volume and the resulting mass emissions of organic HAP in pounds that bypass a control device. For periods when the flow indicator is not operating, report the start date, start time, and duration in hours.

(8) For process vents in ethylene oxide service subject to the requirements of § 63.124, the Periodic Report must include the records for periods specified in paragraph (l)(2) of this section. Indicate the start date and time and end date and time for each period.

(9) For any maintenance vent release exceeding the applicable limits in § 63.113(k)(1), the compliance report must include the information specified in paragraphs (f)(9)(i) through (iv) of this section. For the purposes of this reporting requirement, if an owner or operator complies with § 63.113(k)(1)(iv) then the owner or operator must report each venting event conducted under those provisions and

include an explanation for each event as to why utilization of this alternative was required.

(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 LEL in percent, vessel pressure in psig, or mass in pounds of VOC in the equipment, as applicable, at the start of atmospheric venting. If the 5 psig vessel pressure option in § 63.113(k)(1)(ii) was used and active purging was initiated while the concentration of the vapor was 10 percent or greater of its LEL, also include the concentration of the vapors at the time active purging was initiated.

(iv) An estimate of the mass in pounds of organic HAP released during the entire atmospheric venting event.

(g) Whenever a process change, as defined in § 63.115(e), is made that causes a Group 2 process vent to become a Group 1 process vent, the owner or operator shall submit a report within 180 calendar days after the process change as specified in § 63.151(j). The report shall include:

(1) A description of the process change;

(2) Except as specified in § 63.113(a)(4), the results of the recalculation of the flow rate, organic HAP concentration, and TRE index value required under § 63.115(e) and recorded under paragraph (c), (d), or (e) of this section; and

(3) A statement that the owner or operator will comply with the provisions of § 63.113 for Group 1 process vents by the dates specified in subpart F of this part.

(h) Except as specified in § 63.113(a)(4), whenever a process change, as defined in § 63.115(e), is made that causes a Group 2 process vent with a TRE greater than 4.0 to become a Group 2 process vent with a TRE less than 4.0, the owner or operator shall submit a report within 180 calendar days after the process change. The report may be submitted as part of the next periodic report. The report shall include:

(1) A description of the process change,

(2) The results of the recalculation of the TRE index value required under § 63.115(e) and recorded under paragraph (c) of this section, and

(3) A statement that the owner or operator will comply with the requirements specified in § 63.113(d).

(i) Except as specified in § 63.113(a)(4), whenever a process change, as defined in § 63.115(e), is made that causes a Group 2 process vent with a flow rate less than 0.005 standard cubic meter per minute to become a Group 2 process vent with a flow rate of 0.005 standard cubic meter per minute or greater and a TRE index value less than or equal to 4.0, the owner or operator shall submit a report within 180 calendar days after the process change. The report may be submitted as part of the next periodic report. The report shall include:

(1) A description of the process change,

(2) The results of the recalculation of the flow rate and the TRE determination required under § 63.115(e) and recorded under paragraph (d) of this section, and

(3) A statement that the owner or operator will comply with the requirements specified in § 63.113(d).

(j) Except as specified in § 63.113(a)(4), whenever a process change, as defined in § 63.115(e), is made that causes a Group 2 process vent with an organic HAP concentration less than 50 parts per million by volume to become a Group 2 process vent with an organic HAP concentration of 50 parts per million by volume or greater and a TRE index value less than or equal to 4.0, the owner or operator shall submit a report within 180 calendar days after the process change. The report may be submitted as part of the next periodic report. The report shall include:

(1) A description of the process change,

(2) The results of the recalculation of the organic HAP concentration and the TRE determination required under § 63.115(e) and recorded under paragraph (e) of this section, and

(3) A statement that the owner or operator will comply with the requirements specified in § 63.113(d).

(k) The owner or operator is not required to submit a report of a process change if one of the conditions listed in paragraph (k)(1), (2), (3), or (4) of this section is met.

(1) The process change does not meet the definition of a process change in § 63.115(e), or

(2) The vent stream flow rate is recalculated according to § 63.115(e) and the recalculated value is less than 0.005 standard cubic meter per minute, or

(3) The organic HAP concentration of the vent stream is recalculated according to § 63.115(e) and the recalculated value is less than 50 parts per million by volume, or

(4) Except as specified in § 63.113(a)(4), the TRE index value is recalculated according to § 63.115(e) and the recalculated value is greater than 4.0.

(l) For process vents in ethylene oxide service subject to the requirements of § 63.124, owners and operators must keep the records specified in paragraphs (l)(1) and (2) of this section in addition to those records specified elsewhere in this section.

(1) For process vents, include all uncontrolled, undiluted ethylene oxide concentration measurements, and the calculations used to determine the total uncontrolled ethylene oxide mass emission rate for the sum of all vent gas streams.

(2) If emissions are vented through a closed-vent system to a non-flare control device, then the owner or operator must keep records of all periods during which operating values are outside of the applicable operating limits specified in § 63.124(b)(4) through (6) when regulated material is being routed to the non-flare control device. The record must specify the identification of the control device, the operating parameter, the applicable limit, and the highest (for maximum operating limits) or lowest (for minimum operating limits) value recorded during the period.(m) For each maintenance vent opening subject to the requirements of § 63.113(k), owners and operators must keep the applicable records specified in paragraphs (m)(1) through (5) of this section.

(1) Owners and operators must 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 § 63.113(k). The current copy of the procedures must be retained and available on-site at all times. Previous versions of the standard site procedures, as applicable, must be retained for 5 years.

(2) If complying with the requirements of § 63.113(k)(1)(i), and the concentration of the vapor at the time of the vessel opening exceeds 10 percent of its LEL, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and the concentration of the vapor at the time of the vessel opening.

(3) If complying with the requirements of § 63.113(k)(1)(ii), and either the vessel pressure at the time of the vessel opening exceeds 5 psig or the concentration of the vapor at the time of the active purging was initiated exceeds 10 percent of its LEL, 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 concentration of the vapors in the equipment when active purging was initiated.

(4) If complying with the requirements of § 63.113(k)(1)(iii), records of the estimating procedures used to determine the total quantity of VOC in the equipment and the type and size limits of equipment that contain less than 50 pounds of VOC at the time of maintenance vent opening. For each maintenance vent opening that contains greater than 50 pounds of VOC for which the deinventory procedures specified in paragraph (m)(1) of this section are not followed or for which the equipment opened exceeds the type and size limits established in the records specified in this paragraph (m)(4), records that identify 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.

(5) If complying with the requirements of § 63.113(k)(1)(iv), identification of the maintenance vent, the process units or equipment associated with the maintenance vent, records documenting actions taken to comply with other applicable alternatives and why utilization of this alternative was required, the date of maintenance vent opening, the equipment pressure and concentration of the vapors in the equipment at the time of discharge, an indication of whether active purging was performed and the pressure of the equipment during the installation or removal of the blind if active purging was used, the duration the maintenance vent was open during the blind installation or removal process, 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.

(n) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), paragraphs (d) and (e) of this section no longer apply. Instead, each owner or operator demonstrating that a process vent is a Group 2 process vent based on total organic HAP mass flow rate less than 1.0 pound per hour under § 63.113(l), shall keep up-to-date, readily accessible records of:

(1) Any process changes that increase the vent stream mass flow rate, and

(2) Any recalculation or measurement of the mass flow rate pursuant to § 63.115(g).

■ 63. Amend § 63.119 by:

■ a. Revising paragraph (a) introductory text;

■ b. Adding paragraphs (a)(5) through (7);

■ c. Revising paragraphs (b) introductory text, (b)(5) introductory text, and (b)(5)(ii);

■ d. Adding paragraphs (b)(5)(ix) through (xii) and (b)(7);

■ e. Revising and publishing paragraph (e);

■ f. Revising paragraphs (f)(3) and revising and republishing paragraph (g).

The revisions, additions and republications read as follows:

§ 63.119 Storage vessel provisions—reference control technology.

(a) For each storage vessel to which this subpart applies, the owner or operator shall comply with the requirements of paragraphs (a)(1) through (6) of this section according to the schedule provisions of § 63.100. For each pressure vessel to which this subpart applies, the owner or operator must comply with the requirements of paragraph (a)(7) of this section.

* * * * *

(5) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(11), if the storage vessel (of any capacity and vapor pressure) stores liquid containing ethylene oxide such that the storage vessel is considered to be in ethylene oxide service, as defined in § 63.101, then the owner or operator must comply with the requirements of paragraph (a)(5)(i) or (ii) of this section in addition to all other applicable requirements specified elsewhere in this section.

(i) Reduce emissions of ethylene oxide by venting emissions through a closed vent system to a flare; or

(ii) Reduce emissions of ethylene oxide by venting emissions through a closed vent system to a control device that reduces ethylene oxide by greater than or equal to 99.9 percent by weight, or to a concentration less than 1 ppmv for each storage vessel vent.

(6) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), for each storage vessel subject to paragraph (a)(1), (2), or (5) of this section, the owner or operator must comply with paragraphs (a)(6)(i) through (iv) of this section during storage vessel shutdown operations (*i.e.,* emptying and degassing of a storage vessel) until the vapor space concentration in the storage vessel is less than 10 percent of the LEL, or the organic HAP concentration in the vapor space is equal to or less than of 5,000 ppmv as methane. The owner or operator must determine the concentration using process instrumentation or portable measurement devices and follow procedures for calibration and maintenance according to manufacturer's specifications. The owner or operator must determine the organic HAP concentration using Method 18 or Method 25A of appendix A to part 60 of this chapter; or alternatively, any other method or data that has been validated according to the protocol in Method 301 of appendix A of this part.

(i) Remove liquids from the storage vessel as much as practicable.

(ii) Comply with one of the following:

(A) Reduce emissions of total organic HAP by venting emissions through a closed vent system to a flare.

(B) Reduce emissions of total organic HAP by 95 weight-percent by venting emissions through a closed vent system to any combination of non-flare control devices.

(C) Reduce emissions of total organic HAP by routing emissions to a fuel gas system or process and meet the requirements specified in paragraph (f) of this section.

(iii) Maintain records necessary to demonstrate compliance with the requirements in § 63.102(f) of subpart F of this part including, if appropriate, records of existing standard site procedures used to empty and degas (deinventory) equipment for safety purposes.

(iv) For floating roof storage vessels, the storage vessel may be opened to set up equipment (*e.g.,* making connections to a temporary control device) for the shutdown operations but must not be actively degassed during this time period.

(7) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), for each pressure vessel as defined in § 63.101 that is considered a Group 1 storage vessel (as defined in table 5 of this subpart for existing sources and table 6 of the subpart for new sources), you must operate and maintain the pressure vessel, as specified in paragraphs (a)(7)(i) through (v) of this section.

(i) The pressure vessel must be designed to operate with no detectable emissions at all times.

(ii) Except for connectors in ethylene oxide service, gas/vapor or light liquid valves in ethylene oxide service, light liquid pumps in ethylene oxide service, and PRDs in ethylene oxide service, and except for equipment that meet the criteria specified in § 63.168(h) and (i) (for valves in gas/vapor service and in light liquid service) and in § 63.174(f) and (h) (for connectors in gas/vapor service and in light liquid service), you must monitor each point on the pressure vessel through which total organic hazardous air pollutants could potentially be emitted by conducting initial and annual performance tests using Method 21 of appendix A–7 to part 60 of this chapter

(iii) Each instrument reading greater than 500 ppmv is a violation.

(iv) Estimate the flow rate and total regulated material emissions from the defect. Assume the pressure vessel has been emitting for half of the time since the last performance test, unless other information supports a different assumption.

(v) Whenever total organic hazardous air pollutants are in the pressure vessel, you must operate the pressure vessel as a closed system that vents through a closed vent system to a control device as specified in paragraph (e) of this section, as applicable. For purposes of compliance with this paragraph, a release of total organic hazardous air pollutants through a pressure vessel's pressure relief device to the atmosphere is a violation.

(b) The owner or operator who elects to use a fixed roof and an internal floating roof, as defined in § 63.111, to comply with the requirements of paragraph (a)(1) of this section shall comply with the requirements specified in paragraphs (b)(1) through (7) of this section.

Note: The intent of paragraphs (b)(1) and (2) of this section is to avoid having a vapor space between the floating roof and the stored liquid for extended periods. Storage vessels may be emptied for purposes such as routine storage vessel maintenance, inspections, petroleum liquid deliveries, or transfer operations. Storage vessels where liquid is left on walls, as bottom clingage, or in pools due to floor irregularity are considered completely empty.

* * * * *

(5) Except as provided in paragraph (b)(5)(viii) of this section, each internal floating roof shall meet the specifications listed in paragraphs (b)(5)(i) through (vii) of this section, and (b)(5)(ix) through (xii) of this section.

* * * * *

(ii) Except as specified in paragraph (b)(5)(ix) of this section, 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 shall be equipped with a cover or lid. The cover or lid shall be equipped with a gasket.

* * * * *

(ix) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), paragraph (b)(5)(i) of this section no longer applies. Instead, each opening in the internal floating roof 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.

(x) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), 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.

(xi) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), each opening for a slotted guidepole shall be equipped with one of the control device configurations specified in paragraphs (b)(5)(xi)(A) and (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.

(xii) Each unslotted guidepole cap shall be closed at all times except when gauging the liquid level or taking liquid samples.

* * * * *

(7) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), owners and operators that use a continuous sweep, purge, or inert blanket between the internal floating roof and fixed roof that causes a pressure/vacuum vent to remain continuously open to the atmosphere where uncontrolled emissions are greater than or equal to 1.0 pound per hour of total organic HAP must route emissions through a closed vent system and control device and comply with paragraph (e) of this section.

* * * * *

(e) The owner or operator who elects to use a closed vent system and control device, as defined in § 63.111, to comply with the requirements of paragraph (a)(1) or (2) of this section, or the owner or operator who meets the requirements specified in paragraph (b)(7) of this section, shall comply with the requirements specified in paragraphs (e)(1) through (7) of this section.

(1) Except as provided in paragraph (e)(2) of this section, the control device shall be designed and operated to reduce inlet emissions of total organic HAP by 95 percent or greater. Except as specified in § 63.108(a), if a flare is used as the control device, it shall meet the specifications described in the general control device requirements of § 63.11(b).

(2) If the owner or operator can demonstrate that a control device installed on a storage vessel on or before December 31, 1992 is designed to reduce inlet emissions of total organic HAP by greater than or equal to 90 percent but less than 95 percent, then the control device is required to be operated to reduce inlet emissions of total organic HAP by 90 percent or greater.

(3) Except as specified in (e)(7) of this section, periods of planned routine maintenance of the control device, during which the control device does not meet the specifications of paragraph (e)(1) or (2) of this section, as applicable, shall not exceed 240 hours per year.

(4) Except as specified in (e)(7) of this section, the specifications and requirements in paragraphs (e)(1) and (2) of this section for control devices do not apply during periods of planned routine maintenance.

(5) Except as specified in (e)(7) of this section, the specifications and requirements in paragraphs (e)(1) and (2) of this section for control devices do not apply during a control system malfunction.

(6) An owner or operator may use a combination of control devices to achieve the required reduction of total organic hazardous air pollutants specified in paragraph (e)(1) of this section. An owner or operator may use a combination of control devices installed on a storage vessel on or before December 31, 1992 to achieve the required reduction of total organic hazardous air pollutants specified in paragraph (e)(2) of this section.

(7) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), paragraphs (e)(3) through (5) of this section no longer apply. Instead, whenever gases or vapors containing total organic HAP are routed from a storage vessel through a closed vent system connected to a control device used to comply with the requirements of paragraph (e)(1) or (2) of this section, the control device must be operating, except the control device may only be bypassed for the purpose of performing planned routine maintenance of the control device. When the control device is bypassed,

the owner or operator must comply with paragraphs (e)(7)(i) through (iii) of this section.

(i) The control device may only be bypassed when the planned routine maintenance cannot be performed during periods that storage vessel emissions are vented to the control device.

(ii) On an annual basis, the total time that the closed-vent system or control device is bypassed to perform planned routine maintenance shall not exceed 240 hours per each calendar year.

(iii) The level of material in the storage vessel shall not be increased during periods that the closed vent system or control device is bypassed to perform planned routine maintenance.

(f) * * *

(3) The fuel gas system or process shall be operating at all times when organic hazardous air pollutants emissions are routed to it except as provided in § 63.102(a)(1) and in paragraphs (f)(3)(i) through (iv) of this section. Whenever the owner or operator bypasses the fuel gas system or process, the owner or operator shall comply with the recordkeeping requirement in § 63.123(h). Bypassing is permitted if the owner or operator complies with one or more of the conditions specified in paragraphs (f)(3)(i) through (iv) of this section.

(i) The liquid level in the storage vessel is not increased;

(ii) The emissions are routed through a closed vent system to a control device complying with § 63.119(e); or

(iii) Except as specified in paragraph (f)(3)(iv) of this section, the total aggregate amount of time during which the emissions bypass the fuel gas system or process during the calendar year without being routed to a control device, for all reasons (except start-ups/shutdowns/malfunctions or product changeovers of flexible operation units and periods when the storage vessel has been emptied and degassed), does not exceed 240 hours.

(iv) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), paragraph (f)(3)(iii) of this section no longer applies. Instead, if you elect to route emissions from storage vessels to a fuel gas system or to a process to comply with the requirements of paragraph (a)(1), (2), or (5) of this section, the fuel gas system or process may only be bypassed when the planned routine maintenance cannot be performed during periods that storage vessel emissions are vented to the fuel gas system or process, and the total aggregate amount of time during which the breathing loss emissions bypass the fuel gas system or process during the calendar year without being routed to a control device must not exceed 240 hours. The level of material in the storage vessel shall not be increased during periods that the fuel gas system or process is bypassed to perform routine maintenance.

(g) The owner or operator who elects to vapor balance to comply with the requirements of paragraphs (a)(1) and (2) of this section shall comply with paragraphs (g)(1) through (7) of this section and the recordkeeping requirements of § 63.123(i).

(1) The vapor balancing system must be designed and operated to route organic HAP vapors displaced from loading of the storage vessel to the railcar, tank truck, or barge from which the storage vessel is filled.

(2) Tank trucks and railcars must have a current certification in accordance with the U.S. Department of Transportation pressure test requirements of 49 CFR part 180 for tank trucks and 49 CFR 173.31 for railcars. Barges must have a current certification of vapor-tightness through testing in accordance with 40 CFR 63.565.

(3) Hazardous air pollutants must only be unloaded from tank trucks or railcars when vapor collection systems are connected to the storage vessel's vapor collection system.

(4) No pressure relief device on the storage vessel, or on the railcar or tank truck, shall open during loading or as a result of diurnal temperature changes (breathing losses).

(5) Pressure relief devices must be set to no less than 2.5 psig at all times to prevent breathing losses. Pressure relief devices may be set at values less than 2.5 psig if the owner or operator provides rationale in the notification of compliance status report explaining why the alternative value is sufficient to prevent breathing losses at all times. The owner or operator shall comply with paragraphs (g)(5)(i) through (iii) of this section for each pressure relief valve.

(i) The pressure relief valve shall be monitored quarterly using the method described in § 63.180(b).

(ii) An instrument reading of 500 ppmv or greater defines a leak.

(iii) When a leak is detected, it shall be repaired as soon as practicable, but no later than 5 days after it is detected, and the owner or operator shall comply with the recordkeeping requirements of § 63.181(d)(1) through (4).

(6) Railcars, tank trucks, or barges that deliver HAP to a storage vessel must be reloaded or cleaned at a facility that utilizes the control techniques specified in paragraph (g)(6)(i) or (ii) of this section.

(i) The railcar, tank truck, or barge must be connected to a closed vent system with a control device that reduces inlet emissions of HAP by 95 percent by weight or greater.

(ii) A vapor balancing system designed and operated to collect organic HAP vapor displaced from the tank truck, railcar, or barge during reloading must be used to route the collected HAP vapor to the storage vessel from which the liquid being transferred originated.

(7) The owner or operator of the facility where the railcar, tank truck, or barge is reloaded or cleaned must comply with paragraphs (g)(7)(i) through (iii) of this section.

(i) Submit to the owner or operator of the storage vessel and to the Administrator a written certification that the reloading or cleaning facility will meet the requirements of this section. The certifying entity may revoke the written certification by sending a written statement to the owner or operator of the storage vessel giving at least 90 days notice that the certifying entity is rescinding acceptance of responsibility for compliance with the requirements of this paragraph (g)(7).

(ii) If complying with paragraph (g)(6)(i) of this section, comply with the requirements for closed vent system and control device specified in §§ 63.119 through 63.123. The notification and reporting requirements in § 63.122 do not apply to the owner or operator of the offsite cleaning or reloading facility.

(iii) If complying with paragraph (g)(6)(ii) of this section, keep the records specified in § 63.123(i)(3).

(iv) After the compliance dates specified in § 63.100(k) at an offsite reloading or cleaning facility subject to paragraph (g) of this section, compliance with the monitoring, recordkeeping, and reporting provisions of any other subpart of this part 63 constitutes compliance with the monitoring, recordkeeping, and reporting provisions of paragraph (g)(7)(ii) or (iii) of this section. You must identify in your Notification of Compliance Status report required by § 63.152(b), the subpart to the part 63 with which the owner or operator of the reloading or cleaning facility complies.

■ 64. Amend § 63.120 by:

■ a. Revising paragraphs (b)(9);

■ b. Revising and republishing paragraph (d);

■ c. Revising paragraphs (e) introductory text and (e)(3); and

■ d. Adding paragraph (g).

The revisions, addition, and republication read as follows:

§ 63.120 Storage vessel provisions—procedures to determine compliance.

* * * * *

(b) * * *

(9) The owner or operator shall notify the Administrator in writing at least 30 calendar days in advance of any gap measurements required by paragraph (b)(1) or (2) of this section to afford the Administrator the opportunity to have an observer present.

* * * * *

(d) To demonstrate compliance with § 63.119(e) (storage vessel equipped with a closed vent system and control device) using a control device other than a flare, the owner or operator shall comply with the requirements in paragraphs (d)(1) through (7) of this section, except as provided in paragraphs (d)(8) and (9) of this section.

(1) Except as provided in paragraph (d)(1)(iii) of this section, the owner or operator shall either prepare a design evaluation, which includes the information specified in paragraph (d)(1)(i) of this section or submit the results of a performance test as described in paragraph (d)(1)(ii) of this section.

(i) The design evaluation shall include documentation demonstrating that the control device being used achieves the required control efficiency during reasonably expected maximum filling rate. This documentation is to include a description of the gas stream which enters the control device, including flow and organic HAP content under varying liquid level conditions, and the information specified in paragraphs (d)(1)(i)(A) through (E) of this section, as applicable.

(A) If the control device receives vapors, gases or liquids, other than fuels, from emission points other than storage vessels subject to this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids, other than fuels, received by the control device.

(B) If an enclosed combustion device with a minimum residence time of 0.5 seconds and a minimum temperature of 760 °C is used to meet the emission reduction requirement specified in § 63.119 (e)(1) or (2), as applicable, documentation that those conditions exist is sufficient to meet the requirements of paragraph (d)(1)(i) of this section.

(C) Except as provided in paragraph (d)(1)(i)(B) of this section, for thermal incinerators, the design evaluation shall include the autoignition temperature of the organic HAP, the flow rate of the organic HAP emission stream, the combustion temperature, and the residence time at the combustion temperature.

(D) For carbon adsorbers, the design evaluation shall include the affinity of the organic HAP vapors for carbon, the amount of carbon in each bed, the number of beds, the humidity of the feed gases, the temperature of the feed gases, the flow rate of the organic HAP emission stream, the desorption schedule, the regeneration stream pressure or temperature, and the flow rate of the regeneration stream. For vacuum desorption, pressure drop shall be included.

(E) For condensers, the design evaluation shall include the final temperature of the organic HAP vapors, the type of condenser, and the design flow rate of the organic HAP emission stream.

(ii) If the control device used to comply with § 63.119(e) is also used to comply with § 63.113(a)(2), § 63.126(b)(1), or § 63.139(c), the performance test required by § 63.116(c), § 63.128(a), or § 63.139(d)(1) is acceptable to demonstrate compliance with § 63.119(e). The owner or operator is not required to prepare a design evaluation for the control device as described in paragraph (d)(1)(i) of this section, if the performance tests meets the criteria specified in paragraphs (d)(1)(ii)(A) and (B) of this section.

(A) The performance test demonstrates that the control device achieves greater than or equal to the required control efficiency specified in § 63.119 (e)(1) or (2), as applicable; and

(B) The performance test is submitted as part of the Notification of Compliance Status required by § 63.151(b). If the performance test report is submitted electronically through the EPA's CEDRI in accordance with § 63.152(h), the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the notification of compliance status report in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the notification of compliance status report is submitted.

(iii) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), if the owner or operator vents emissions through a closed vent system to an adsorber(s) that cannot be regenerated or a regenerative adsorber(s) that is regenerated offsite, then the owner or operator must install a system of two or more adsorber units in series and comply with the requirements specified in paragraphs (d)(1)(iii)(A) through (C) of this section.

(A) Conduct an initial performance test or design evaluation of the adsorber and establish the breakthrough limit and adsorber bed life.

(B) Monitor the HAP or total organic compound (TOC) concentration through a sample port at the outlet of the first adsorber bed in series according to the schedule in paragraph (d)(1)(iii)(C)(*2*) of this section. The owner or operator must measure the concentration of HAP or TOC using either a portable analyzer, in accordance with Method 21 of appendix A–7 to part 60 of this chapter using methane, propane, isobutylene, or the primary HAP being controlled as the calibration gas or Method 25A of appendix A–7 to part 60 using methane, propane, or the primary HAP being controlled as the calibration gas.

(C) Comply with paragraph (d)(1)(iii)(C)(*1*) of this section and comply with the monitoring frequency according to paragraph (d)(1)(iii)(C)(*2*) of this section.

(*1*) The first adsorber in series must be replaced immediately when breakthrough, as defined in § 63.101, is detected between the first and second adsorber. The original second adsorber (or a fresh canister) will become the new first adsorber and a fresh adsorber will become the second adsorber. For purposes of this paragraph, "immediately" means within 8 hours of the detection of a breakthrough for adsorbers of 55 gallons or less, and within 24 hours of the detection of a breakthrough for adsorbers greater than 55 gallons. The owner or operator must monitor at the outlet of the first adsorber within 3 days of replacement to confirm it is performing properly.

(*2*) Based on the adsorber bed life established according to paragraph (d)(1)(iii)(A) of this section and the date the adsorbent was last replaced, conduct monitoring to detect breakthrough at least monthly if the adsorbent has more than 2 months of life remaining, at least weekly if the adsorbent has between 2 months and 2 weeks of life remaining, and at least daily if the adsorbent has 2 weeks or less of life remaining.

(2) The owner or operator shall submit, as part of the Notification of Compliance Status required by § 63.151 (b), a monitoring plan containing the information specified in paragraph (d)(2)(i) of this section and in either paragraph (d)(2)(ii) or (iii) of this section. This paragraph does not apply if the owner or operator complies with paragraph (d)(1)(iii) of this section.

(i) 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 (*e.g.,* when the liquid level in the storage vessel is being raised); and either

(ii) The documentation specified in paragraph (d)(1)(i) of this section, if the owner or operator elects to prepare a design evaluation; or

(iii) The information specified in paragraph (d)(2)(iii) (A) and (B) of this section if the owner or operator elects to submit the results of a performance test.

(A) Identification of the storage vessel and control device for which the performance test will be submitted, and

(B) Identification of the emission point(s) that share the control device with the storage vessel and for which the performance test will be conducted.

(3) The owner or operator shall submit, as part of the Notification of Compliance Status required by § 63.152(b) of this subpart, the information specified in paragraphs (d)(3)(i) and, if applicable, (d)(3)(ii) of this section. This paragraph does not apply if the owner or operator complies with paragraph (d)(1)(iii) of this section.

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

(ii) Results of the performance test described in paragraph (d)(1)(ii) of this section. If the performance test report is submitted electronically through the EPA's CEDRI in accordance with § 63.152(h), the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the notification of compliance status report in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the notification of compliance status report is submitted.

(4) The owner or operator shall demonstrate compliance with the requirements of §§ 63.119(e)(3) and (7) (planned routine maintenance of a control device, during which the control device does not meet the specifications of § 63.119 (e)(1) or (2), as applicable, shall not exceed 240 hours per year) by including in each Periodic Report required by § 63.152(c) the information specified in § 63.122(g)(1).

(5) The owner or operator shall monitor the parameters specified in the Notification of Compliance Status required in § 63.152(b) or in the operating permit and shall operate and maintain the control device such that the monitored parameters remain within the ranges specified in the Notification of Compliance Status.

(6) Except as provided in paragraph (d)(7) of this section, each closed vent system shall be inspected as specified in § 63.148. The initial and annual inspections required by § 63.148(b) shall be done during filling of the storage vessel.

(7) For any fixed roof tank and closed vent system that are operated and maintained under negative pressure, the owner or operator is not required to comply with the requirements specified in § 63.148.

(8) A design evaluation or performance test is not required, if the owner or operator uses a combustion device meeting the criteria in paragraph (d)(8)(i), (ii), (iii), or (iv) of this section.

(i) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(ii) A boiler or process heater burning hazardous waste for which the owner or operator:

(A) Has been issued a final permit under part 270 of this chapter and complies with the requirements of part 266, subpart H, of this chapter;

(B) Has certified compliance with the interim status requirements of part 266, subpart H, of this chapter;

(C) Has submitted a Notification of Compliance under § 63.1207(j) and complies with the requirements of subpart EEE of this part; or

(D) Complies with subpart EEE of this part and will submit a Notification of Compliance under § 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

(iii) A hazardous waste incinerator for which the owner or operator:

(A) Has been issued a final permit under part 270 of this chapter and complies with the requirements of part 264, subpart O, of this chapter;

(B) Has certified compliance with the interim status requirements of part 265, subpart O, of this chapter;

(C) Has submitted a Notification of Compliance under § 63.1207(j) and complies with the requirements subpart EEE of this part; or

(D) Complies with the requirements subpart EEE of this part and will submit a Notification of Compliance under § 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

(iv) A boiler or process heater into which the vent stream is introduced with the primary fuel.

(9) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(11), paragraph (d)(1)(i) of this section no longer applies to storage vessels in ethylene oxide service, as defined in § 63.101.

(e) Except as specified in paragraph (a) of § 63.108, to demonstrate compliance with § 63.119(e) (storage vessel equipped with a closed vent system and control device) using a flare, the owner or operator shall comply with the requirements in paragraphs (e)(1) through (6) of this section.

* * * * *

(3) The owner or operator shall demonstrate compliance with the requirements of §§ 63.119(e)(3) and (7) (planned routine maintenance of a flare, during which the flare does not meet the specifications of § 63.119(e)(1), shall not exceed 240 hours per year) by including in each Periodic Report required by § 63.152(c) the information specified in § 63.122(g)(1).

* * * * *

(g) To demonstrate compliance with the emission limits and work practice standards specified in § 63.119(a)(5) for storage vessels in ethylene oxide service, owners and operators must meet the requirements specified in § 63.124.

■ 65. Amend § 63.122 by:

■ a. Revising paragraphs (a)(4) and (c)(2);

■ b. Revising and republishing paragraph (g); and

■ c. Adding paragraph (i).

The revisions, addition, and republication read as follows:

§ 63.122 Storage vessel provisions—reporting.

(a) * * *

(4) The owner or operator shall submit Periodic Reports as required by § 63.152(c) of this subpart and shall submit as part of the Periodic Reports the information specified in paragraphs (d), (e), (f), (g), and (i) of this section.

* * * * *

(c) * * *

(2) Except as specified in paragraph (a) of § 63.108, if a flare is used, the owner or operator shall submit the information specified in § 63.120(e)(2)(i), (e)(2)(ii) through (iii).

* * * * *

(g) An owner or operator who elects to comply with § 63.119(e) by installing a closed vent system and control device shall submit, as part of the next Periodic Report required by § 63.152(c), the information specified in paragraphs (g)(1) through (4) of this section.

(1) As required by § 63.120(d)(4) and (e)(3), the Periodic Report shall include the information specified in paragraphs

(g)(1)(i) through (iii) of this section for those planned routine maintenance operations that would require the control device not to meet the requirements of § 63.119 (e)(1) or (2), as applicable.

(i) 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.

(ii) 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 § 63.119 (e)(1) or (2), as applicable, due to planned routine maintenance.

(iii) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), for each storage vessel for which planned routine maintenance was performed during the previous 6 months, report the identification of the storage vessel and the height of the liquid in the storage vessel at the time the control device is bypassed to conduct the planned routine maintenance and at the time the control device is placed back in service after completing the routine maintenance. These reports shall include the date and time the liquid height was measured.

(2) 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 in accordance with § 63.120(d)(3)(i). The description shall include the information specified in paragraphs (g)(2)(i) and (ii) of this section.

(i) Identification of the control device for which the measured parameters were outside of the established ranges, the date, and the parameter that was outside of the established ranges, and

(ii) Cause for the measured parameters to be outside of the established ranges.

(3) Except as specified in paragraph (a) of § 63.108, if a flare is used, the Periodic Report shall describe each occurrence when the flare does not meet the general control device requirements specified in § 63.11(b) and shall include the information specified in paragraphs (g)(3)(i) and (ii) of this section.

(i) Identification of the flare which does not meet the general requirements specified in § 63.11(b), and

(ii) Reason the flare did not meet the general requirements specified in § 63.11(b).

(4) For each nonregenerative adsorber and regenerative adsorber that is regenerated offsite subject to the requirements in § 63.120(d)(1)(iii), the owner or operator must report the date of each instance when breakthrough, as defined in § 63.101, is detected between the first and second adsorber and the adsorber is not replaced according to § 63.120(d)(1)(iii)(C)(*1*) and an identification of the adsorber for which breakthrough was detected.

* * * * *

(i) For pressure vessels subject to the requirements of § 63.119(a)(7), if you obtain an instrument reading greater than 500 ppmv of a leak when monitoring a pressure vessel in accordance with § 63.119(a)(7)(ii), then the Periodic Report must include an identification of the pressure vessel and a copy of the records specified in § 63.123(b)(2).

■ 66. Amend § 63.123 by adding paragraph (b), revising paragraphs (h) and (i)(3)(i), and adding paragraphs (j) and (k) to read as follows:

§ 63.123 Storage vessel provisions—recordkeeping.

* * * * *

(b) Each owner or operator of a pressure vessel subject to the requirements of § 63.119(a)(7) shall keep readily accessible records as specified in paragraphs (b)(1) and (2) of this section.

(1) The date of each performance test conducted according to § 63.119(a)(7)(ii).

(2) The record of each performance test conducted according to § 63.119(a)(7)(ii), including the following:

(i) Date each defect was detected and the instrument reading (in ppmv) during the performance test.

(ii) Date of the next performance test that shows the instrument reading is less than 500 ppmv and the instrument reading (in ppmv) during the performance test.

(iii) Start and end dates of each period after the date in paragraph (b)(2)(i) of this section when the pressure vessel was completely empty.

(iv) Estimated emissions from each defect.

* * * * *

(h) An owner or operator who uses the bypass provisions of § 63.119(f)(3) shall keep in a readily accessible location the records specified in paragraphs (h)(1) through (3) of this section.

(1) The reason it was necessary to bypass the process equipment or fuel gas system;

(2) The duration of the period when the process equipment or fuel gas system was bypassed;

(3) Documentation or certification of compliance with the applicable provisions of § 63.119(f)(3)(i) through (iv).

(i) * * *

(3) * * *

(i) A record of the equipment to be used and the procedures to be followed when reloading the railcar, tank truck, or barge and displacing vapors to the storage vessel from which the liquid originates.

* * * * *

(j) For each nonregenerative adsorber and regenerative adsorber that is regenerated offsite subject to the requirements in § 63.120(d)(1)(iii), the owner or operator must keep the applicable records specified in (j)(1) through (3) of this section.

(1) Breakthrough limit and bed life established according to § 63.120(d)(1)(iii)(A).

(2) Each outlet HAP or TOC concentration measured according to § 63.120(d)(1)(iii)(B) and (C).

(3) Date and time you last replaced the adsorbent.

(k) For storage vessels in ethylene oxide service, subject to the requirements of § 63.124, owners and operators must keep the records specified in paragraphs (k)(1) and (2) of this section in addition to those records specified elsewhere in this section.

(1) For storage vessels in ethylene oxide service, records of the concentration of ethylene oxide of the fluid stored in each storage vessel.

(2) If emissions are vented through a closed-vent system to a non-flare control device, then the owner or operator must keep records of all periods during which operating values are outside of the applicable operating limits specified in § 63.124(b)(4) through (6) when regulated material is being routed to the non-flare control device. The record must specify the operating parameter, the applicable limit, and the highest (for maximum operating limits) or lowest (for minimum operating limits) value recorded during the period.

■ 67. Add § 63.124 to read as follows:

§ 63.124 Process vents and storage vessels that are in ethylene oxide service—procedures to determine compliance.

This section applies beginning no later than the compliance dates specified in § 63.100(k)(11). In order to demonstrate compliance with the emission limits and work practice standards specified in § 63.113(j) (for process vents in ethylene oxide service) and § 63.119(a)(5) (for storage vessels in ethylene oxide service), owners and operators must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) For initial compliance, owners and operators must comply with paragraphs (a)(1) through (4) of this section, as applicable.

(1) If an owner or operator chooses to reduce emissions of ethylene oxide by venting emissions through a closed vent system to a flare as specified in § 63.113(j)(1) or § 63.119(a)(5)(i), then the owner or operator must comply with § 63.148 and conduct the initial visible emissions demonstration required by § 63.670(h) as specified in § 63.108.

(2) If an owner or operator chooses to reduce emissions of ethylene oxide by venting emissions through a closed vent system to a non-flare control device that reduces ethylene oxide by greater than or equal to 99.9 percent by weight as specified in § 63.113(j)(2) or § 63.119(a)(5)(ii), then the owner or operator must comply with § 63.148 and paragraphs (a)(2)(i) through (viii) of this section.

(i) Conduct an initial performance test of the control device that is used to comply with the percent reduction requirement at the inlet and outlet of the control device. For purposes of compliance with this paragraph, owners and operators may not use a design evaluation. This paragraph does not apply if the conditions specified in paragraphs (a)(2)(i)(A) through (D) of this section are met for a previously conducted measurement or performance test.

(A) No changes have been made to the process since the time of the measurement or performance test;

(B) The operating conditions and test methods used during measurement or performance test conform to the ethylene oxide related requirements of this subpart;

(C) The control device and process parameter values established during the previously conducted measurement or performance test are used to demonstrate continuous compliance with the ethylene oxide related requirements of this subpart; and

(D) The previously conducted measurement or performance test was completed within the last 60 months.

(ii) Conduct the performance test according to the procedures in § 63.116(c). Except as specified in § 63.109(a)(6), use Method 18 of appendix A–6 to part 60 of this chapter or Method 320 of appendix A to this part to determine the ethylene oxide concentration. Use Method 1 or 1A of appendix A–1 to part 60 of this chapter to select the sampling sites at each sampling location. Determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of appendix A–2 to part 60 of this chapter. Use Method 4 of appendix A–3 to part 60 of this chapter convert the volumetric flowrate to a dry basis.

(iii) Calculate the mass emission rate of ethylene oxide entering the control device and exiting the control device using equations 1 and 2 to this paragraph.

Equations 1 and 2 to Paragraph (a)(2)(iii)

$E_{,inlet} = K\ C_{,inlet}\ M\ Q_{inlet}$ (Eq. 1)

$E_{,outlet} = K\ C_{,outlet}\ M\ Q_{outlet}$ (Eq. 2)

Where:

$E_{,inlet}$, $E_{,outlet}$ = Mass rate of ethylene oxide at the inlet and outlet of the control device, respectively, kilogram per hour.

$C_{,inlet}$, $C_{,outlet}$ = Concentration of ethylene oxide in the gas stream at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M = Molecular weight of ethylene oxide, 44.05 grams per gram-mole.

Q_{inlet}, Q_{outlet} = Flow rate of the gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

K = Constant, 2.494 × 10 − 6 (parts per million) − 1 (gram-mole per standard cubic meter) (kilogram per gram) (minutes per hour), where standard temperature (gram-mole per standard cubic meter) is 20 °C.

(iv) Calculate the percent reduction from the control device using equation 3 to this paragraph. An owner or operator has demonstrated initial compliance with § 63.113(j)(2) or § 63.119(a)(5)(ii) if the overall reduction of ethylene oxide is greater than or equal to 99.9 percent by weight.

Equation 3 to Paragraph (a)(2)(iv)

$\text{Percent reduction} = (E_{,inlet} - E_{,outlet})/E_{,inlet} * 100$ (Eq.3)

Where:

$E_{,inlet}$, $E_{,outlet}$ = Mass rate of ethylene oxide at the inlet and outlet of the control device, respectively, kilogram per hour, calculated using Equations 1 and 2 to paragraph (a)(2)(iii) of this section.

(v) If a new control device is installed, then conduct a performance test of the new device following the procedures in paragraphs (a)(2)(i) through (iv) of this section.

(vi) If an owner or operator vents emissions through a closed vent system to a scrubber with a reactant tank, then the owner or operator must establish operating parameter limits by monitoring the operating parameters specified in paragraphs (a)(2)(vi)(A) through (C) of this section during the performance test.

(A) Scrubber liquid-to-gas ratio (L/G), determined from the total scrubber liquid inlet flow rate and the inlet or exit gas flow rate. Determine the average L/G during the performance test as the average of the test run averages. Alternatively, separately monitor the total scrubber liquid flow rate and gas flow rate through the scrubber. Determine the average total scrubber liquid flow rate and gas flow through the scrubber as the average of the test run averages.

(B) Scrubber liquid pH of the liquid in the reactant tank. The pH may be measured at any point between the discharge from the scrubber column and the inlet to the reactant tank. Determine the average pH during the performance test as the average of the test run averages.

(C) Temperature of the scrubber liquid entering the scrubber column. The temperature may be measured at any point after the heat exchanger and prior to entering the top of the scrubber column. Determine the average inlet scrubber liquid temperature as the average of the test run averages.

(vii) If an owner or operator vents emissions through a closed vent system to a thermal oxidizer, then the owner or operator must establish operating parameter limits by monitoring the operating parameters specified in paragraphs (a)(2)(vii)(A) and (B) of this section during the performance test.

(A) Combustion chamber temperature. Determine the average combustion chamber temperature during the performance test as the average of the test run averages.

(B) Flue gas flow rate. Determine the average flue gas flow rate during the performance test as the average of the test run averages.

(viii) If an owner or operator vents emissions through a closed vent system to a control device other than a flare, scrubber with a reactant tank, or thermal oxidizer, then the owner or operator must notify the Administrator of the operating parameters that are planned to be monitored during the performance test prior to establishing operating parameter limits for the control device.

(3) If an owner or operator chooses to reduce emissions of ethylene oxide by venting emissions through a closed vent system to a non-flare control device that reduces ethylene oxide to less than 1 ppmv as specified in § 63.113(j)(2) or § 63.119(a)(5)(ii), then the owner or operator must comply with § 63.148 and either paragraph (a)(3)(i) or (ii) of this section.

(i) Install a continuous emissions monitoring system (CEMS) to continuously monitor the ethylene oxide concentration at the exit of the control device. The CEMS must meet the requirements of either paragraph (a)(3)(i)(A) or (B) of this section. Comply with the requirements specified in § 63.2450(j) for CEMS.

(A) An FTIR CEMS meeting the requirements of Performance Specification 15 of appendix B to part 60 of this chapter.

(B) A gas chromatographic CEMS meeting the requirements of Performance Specification 9 of appendix B to part 60 of this chapter.

(ii) If the owner or operator does not install a CEMS under paragraph (a)(3)(i) of this section, then the owner or operator must comply with paragraphs (a)(3)(ii)(A) through (C) of this section.

(A) Conduct an initial performance test at the outlet of the control device that is used to comply with the concentration requirement.

(B) Conduct the performance test according to the procedures in § 63.116(c). Except as specified in § 63.109(a)(6), use Method 18 of appendix A–6 to part 60 of this chapter or Method 320 of appendix A to this part to determine the ethylene oxide concentration. If the non-flare control device is a combustion device, correct the ethylene oxide concentration to 3 percent oxygen according to § 63.116(c)(iii)(B), except ''TOC or organic HAP'' and ''TOC (minus methane and ethane) or organic HAP'' in the Variables C_c and C_m must be replaced with ''ethylene oxide''. An owner or operator has demonstrated initial compliance with § 63.113(j)(2) or § 63.119(a)(5)(ii), if the ethylene oxide concentration is less than 1 ppmv.

(C) Comply with the requirements specified in paragraphs (a)(2)(v) through (viii) of this section, as applicable.

(4) If owners and operators choose to reduce emissions of ethylene oxide by venting emissions through a closed vent system to a non-flare control device that reduces ethylene oxide to less than 5 pounds per year for all combined process vents within the process as specified in § 63.113(j)(2), then the owner or operator must comply with § 63.148 and paragraphs (a)(4)(i) through (iv) of this section.

(i) Conduct an initial performance test of the control device that is used to comply with the mass emission limit requirement at the outlet of the control device.

(ii) Conduct the performance test according to the procedures in § 63.116(c). Except as specified in § 63.109(a)(6), use Method 18 of appendix A–6 to part 60 of this chapter or Method 320 of appendix A to this part to determine the ethylene oxide concentration. Use Method 1 or 1A of appendix A–1 to part 60 of this chapter to select the sampling site. Determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of 40 CFR part 60, appendix A–2. Use Method 4 of appendix A–3 to part 60 of this chapter to convert the volumetric flowrate to a dry basis.

(iii) Calculate the mass emission rate of ethylene oxide exiting the control device using Equation 2 to paragraph (a)(2)(iii) of this section. An owner or operator has demonstrated initial compliance with § 63.113(j)(2) if the ethylene oxide from all process vents (controlled and uncontrolled) within the process is less than 5 pounds per year when combined.

(iv) Comply with the requirements specified in paragraphs (a)(2)(v) through (viii) of this section, as applicable.

(b) For continuous compliance, owners and operators must comply with paragraphs (b)(1) through (6) of this section, as applicable.

(1) If an owner or operator chooses to reduce emissions of ethylene oxide by venting emissions through a closed vent system to a flare as specified in § 63.113(j)(1) or § 63.119(a)(5)(i), then the owner or operator must comply with §§ 63.148 and 63.108.

(2) If you choose to reduce emissions of ethylene oxide by venting emissions through a closed-vent system to a non-flare control device that reduces ethylene oxide to less than 1 ppmv as specified in § 63.113(j)(2) or § 63.119(a)(5)(ii), and you choose to comply with paragraph (a)(3)(i) of this section, then continuously monitor the ethylene oxide concentration at the exit of the control device using an FTIR CEMS meeting the requirements of Performance Specification 15 of appendix B to part 60 of this chapter and § 63.2450(j). If an owner or operator uses an FTIR CEMS, then the owner or operator does not need to conduct the performance testing required in paragraph (b)(3) of this section or the operating parameter monitoring required in paragraphs (b)(4) through (6) of this section.

(3) Conduct a performance test no later than 60 months after the previous performance test and reestablish operating parameter limits following the procedures in paragraph (a)(2) through (4) of this section. The Administrator may request a repeat performance test at any time. For purposes of compliance with this paragraph, owners and operators may not use a design evaluation.

(4) If an owner or operator vents emissions through a closed vent system to a scrubber with a reactant tank, then the owner or operator must comply with § 63.148 and meet the operating parameter limits specified in paragraphs (b)(4)(i) through (v) of this section.

(i) Minimum scrubber liquid-to-gas ratio (L/G), equal to the average L/G measured during the most recent performance test. Determine total scrubber liquid inlet flow rate with a flow sensor with a minimum accuracy of at least ±5 percent over the normal range of flow measured, or 1.9 liters per minute (0.5 gallons per minute), whichever is greater. Determine gas flow rate at either the inlet or the exit of the scrubber with a flow sensor with a minimum 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. If gas flow rate is determined at the inlet of the scrubber, ensure that all gas flow through the scrubber is accounted for at the measurement location. Compliance with the minimum L/G operating limit must be determined continuously on a 1-hour block basis. Alternatively, minimum total scrubber liquid flow rate, equal to the average total scrubber liquid inlet flow rate measured during the most recent performance test, and maximum gas flow rate through the scrubber, equal to the average gas flow rate through the scrubber during the most recent performance test. Compliance with the total scrubber liquid flow rate and gas flow rate through the scrubber must be determined continuously on a 1-hour block basis.

(ii) Maximum scrubber liquid pH of the liquid in the reactant tank, equal to the average pH measured during the most recent performance test. Compliance with the pH operating limit must be determined continuously on a 1-hour block basis. Use a pH sensor with a minimum accuracy of ±0.2 pH units.

(iii) Pressure drop across the scrubber column, within the pressure drop range specified by the manufacturer or established based on engineering analysis. Compliance with the pressure drop operating limit must be determined continuously on a 1-hour block basis. Use pressure sensors with a minimum accuracy of ±5 percent over the normal operating range or 0.12 kilopascals, whichever is greater.

(iv) Maximum temperature of the scrubber liquid entering the scrubber column, equal to the average temperature measured during the most recent performance test. Compliance with the inlet scrubber liquid temperature operating limit must be determined continuously on a 1-hour block basis. Use a temperature sensor with a minimum accuracy of ±1 percent over the normal range of the temperature measured, expressed in degrees Celsius, or 2.8 degrees Celsius, whichever is greater.

(v) Liquid feed pressure to the scrubber column within the feed pressure range specified by the manufacturer or established based on engineering analysis. Compliance with the liquid feed pressure operating limit must be determined continuously on a 1-hour block basis. Use a pressure sensor with a minimum accuracy of ±5 percent over the normal operating range or 0.12 kilopascals, whichever is greater.

(5) If an owner or operator vents emissions through a closed vent system to a thermal oxidizer, then the owner or operator must comply with § 63.148, and the owner or operator must meet the operating parameter limits specified in paragraphs (b)(5)(i) and (ii) of this section and the requirements in paragraph (b)(5)(iii) of this section.

(i) Minimum combustion chamber temperature, equal to the average combustion chamber temperature measured during the most recent performance test. Determine combustion chamber temperature with a temperature sensor with a minimum accuracy of at least ±1 percent over the normal range of temperature measured, expressed in degrees Celsius, or 2.8 degrees Celsius, whichever is greater. Compliance with the minimum combustion chamber temperature operating limit must be determined continuously on a 1-hour block basis.

(ii) Maximum flue gas flow rate, equal to the average flue gas flow rate measured during the most recent performance test. Determine flue gas flow rate with a flow sensor with a minimum 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. Compliance with the maximum flue gas flow rate operating limit must be determined continuously on a 1-hour block basis.

(iii) The owner or operator must maintain the thermal oxidizer in accordance with good combustion practices that ensure proper combustion. Good combustion practices include, but are not limited to, proper burner maintenance, proper burner alignment, proper fuel to air distribution and mixing, routine inspection, and preventative maintenance.

(6) If an owner or operator vents emissions through a closed vent system to a control device other than a flare, scrubber with a reactant tank, or thermal oxidizer, then the owner or operator must comply with § 63.148, and the owner or operator must monitor the operating parameters identified in paragraph (a)(2)(viii) of this section and meet the established operating parameter limits to ensure continuous compliance. The frequency of monitoring and averaging time will be determined based upon the information provided to the Administrator.

■ 68. Amend § 63.126 by revising paragraphs (b)(1), (b)(2)(i), (d)(1)(i) and (ii), (d)(3)(i), (h) and (i) to read as follows:

§ 63.126 Transfer operations provisions—reference control technology.

* * * * *

(b) * * *

(1) Use a control device to reduce emissions of total organic hazardous air pollutants by 98 weight-percent or to an exit concentration of 20 parts per million by volume. For combustion devices, the emission reduction or concentration shall be calculated on a dry basis, corrected to 3-percent oxygen. 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. Compliance may be achieved by using any combination of combustion, recovery, and/or recapture devices.

(2) * * *

(i) Except as specified in § 63.108(a), the flare shall comply with the requirements of § 63.11(b).

* * * * *

(d) * * *

(1) * * *

(i) Except as provided in paragraph (d)(1)(ii) of this section, the halogen reduction device shall reduce overall emissions of hydrogen halides and halogens, as defined in § 63.111, by 99 percent or shall reduce the outlet mass emission rate of total hydrogen halides and halogens to 0.45 kilograms per hour or less.

(ii) If a scrubber or other halogen reduction device was installed prior to December 31, 1992, the halogen reduction device shall reduce overall emissions of hydrogen halides and halogens, as defined in § 63.111, by 95 percent or shall reduce the outlet mass of total hydrogen halides and halogens to less than 0.45 kilograms per hour.

* * * * *

(3) * * *

(i) The vent stream concentration of each organic compound containing halogen atoms (parts per million by volume by compound) shall be determined based on the following procedures:

(A) Process knowledge that no halogen or hydrogen halides are present in the process, or

(B) Applicable engineering assessment as specified in § 63.115(d)(1)(iii), or

(C) Concentration of organic compounds containing halogens measured by Method 18 of appendix A to part 60 of this chapter,

(D) Any other method or data that has been validated according to the applicable procedures in Method 301 of appendix A of this part, or

(E) ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18 of appendix A–6 to part 60 of this chapter, if the target compounds are all known and are all listed in section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method.

* * * * *

(h) Except as specified in paragraph (h)(1) of this section, the owner or operator of a transfer rack subject to the provisions of this subpart shall ensure that no pressure-relief device in the transfer rack's vapor collection system or in the organic hazardous air pollutants loading equipment of each tank truck or railcar shall begin to open during loading. Pressure relief devices needed for safety purposes are not subject to this paragraph (h).

(1) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), this paragraph (h) does not apply. Instead, pressure relief devices are subject to the requirements specified in § 63.165(e).

(2) [Reserved]

(i) Each valve in the vent system that would divert the vent stream to the atmosphere, either directly or indirectly, shall be secured in a non-diverting position using a carseal or a lock-and-key type configuration, or shall be equipped with a flow indicator. Except as specified in paragraph (i)(1) of this section, equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and pressure relief devices needed for safety purposes is not subject to this paragraph (i).

(1) For each source as defined in § 63.101, on and after July 15, 2027, the last sentence in paragraph (i) of this section no longer applies. Instead, the exemptions specified in paragraphs (i)(1)(i) and (ii) of this section apply.

(i) Except for pressure relief devices subject to § 63.165(e)(4) of subpart H of this part, equipment such as low leg drains and equipment subject to the requirements of subpart H of this part are not subject to this paragraph (i).

(ii) Open-ended valves or lines that use a cap, blind flange, plug, or second valve and follow the requirements specified in § 60.482–6(a)(2), (b), and (c) or follow requirements codified in another regulation that are the same as § 60.482–6(a)(2), (b), and (c) are not subject to this paragraph (i).

(2) [Reserved]

■ 69. Amend § 63.127 by:

■ a. Revising paragraphs (a)(2), (a)(4)(ii)(C), and (b)(3);

■ b. Adding paragraph (b)(4); and

■ c. Revising and republishing paragraph (d).

The revisions, addition, and republication read as follows:

§ 63.127 Transfer operations provisions—monitoring requirements.

(a) * * *

(2) Where a flare is used, except as specified in § 63.108(a), a device (including but not limited to a thermocouple, infrared sensor, or an ultra-violet beam sensor) capable of continuously detecting the presence of a pilot flame is required.

* * * * *

(4) * * *

(ii) * * *

(C) The owner or operator may prepare and implement a gas stream flow determination plan that documents an appropriate method which will be used to determine the gas stream flow. The plan shall require determination of gas stream flow by a method which will at least provide a value for either a representative or the highest gas stream flow anticipated in the scrubber during representative operating conditions other than start-ups, shutdowns, or malfunctions. The plan shall include a description of the methodology to be followed and an explanation of how the selected methodology will reliably determine the gas stream flow, and a description of the records that will be maintained to document the determination of gas stream flow. The owner or operator shall maintain the plan as specified in § 63.103(c). For each source as defined in § 63.101, on and after July 15, 2027, the phrase ‘‘other than start-ups, shutdowns, or malfunctions’’ in this paragraph no longer applies.

(b) * * *

(3) Except as specified in paragraph (b)(4) of this section, where a carbon adsorber is used, an integrating regeneration stream flow monitoring device having an accuracy of ±10 percent or better, capable of recording the total regeneration stream mass flow for each regeneration cycle; and a carbon bed temperature monitoring device, capable of recording the temperature of the carbon bed after regeneration and within 15 minutes of completing any cooling cycle shall be used.

(4) Beginning no later than the compliance dates specified in § 63.100(k)(10), if the owner or operator vents emissions through a closed vent system to an adsorber(s) that cannot be regenerated or a regenerative adsorber(s) that is regenerated offsite, then the owner or operator must install a system of two or more adsorber units in series and comply with the requirements specified in paragraphs (b)(4)(i) through (iii) of this section.

(i) Conduct an initial performance test or design evaluation of the adsorber and establish the breakthrough limit and adsorber bed life.

(ii) Monitor the HAP or total organic compound (TOC) concentration through a sample port at the outlet of the first adsorber bed in series according to the schedule in paragraph (b)(4)(iii)(B) of this section. The owner or operator must measure the concentration of HAP or TOC using either a portable analyzer, in accordance with Method 21 of appendix A–7 to part 60 of this chapter using methane, propane, isobutylene, or the primary HAP being controlled as the calibration gas or Method 25A of part 60, appendix A–7, using methane, propane, or the primary HAP being controlled as the calibration gas.

(iii) Comply with paragraph (b)(4)(iii)(A) of this section and comply with the monitoring frequency according to paragraph (b)(4)(iii)(B) of this section.

(A) The first adsorber in series must be replaced immediately when breakthrough, as defined in § 63.101, is detected between the first and second adsorber. The original second adsorber (or a fresh canister) will become the new first adsorber and a fresh adsorber will become the second adsorber. For purposes of this paragraph, ‘‘immediately’’ means within 8 hours of the detection of a breakthrough for adsorbers of 55 gallons or less, and within 24 hours of the detection of a breakthrough for adsorbers greater than 55 gallons. The owner or operator must monitor at the outlet of the first adsorber within 3 days of replacement to confirm it is performing properly.

(B) Based on the adsorber bed life established according to paragraph (b)(4)(i) of this section and the date the adsorbent was last replaced, conduct monitoring to detect breakthrough at least monthly if the adsorbent has more than 2 months of life remaining, at least weekly if the adsorbent has between 2 months and 2 weeks of life remaining, and at least daily if the adsorbent has 2 weeks or less of life remaining.

* * * * *

(d) The owner or operator of a Group 1 transfer rack using a closed vent system that contains bypass lines that could divert a vent stream flow away from the control device used to comply with § 63.126(b) shall comply with paragraph (d)(1) or (2) and (d)(3) of this section. Except as specified in paragraph (d)(3) of this section, equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and pressure relief valves needed for safety purposes are not subject to this paragraph.

(1) Properly install, maintain, and operate a flow indicator that takes a reading at least once every 15 minutes. Records shall be generated as specified in § 63.130(b). 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 closed position with a car-seal or a lock-and-key type configuration.

(i) 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.

(ii) If a car-seal has been broken or a valve position changed, the owner or operator shall record that the vent stream has been diverted. The car-seal or lock-and-key combination shall be returned to the secured position as soon as practicable but not later than 15 calendar days after the change in position is detected.

(3) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10):

(i) The use of a bypass line at any time on a closed vent system to divert emissions (subject to the emission standards in § 63.112) to the atmosphere or to a control device not meeting the requirements specified in this subpart is an emissions standards violation.

(ii) The last sentence in paragraph (d) of this section no longer applies. Instead, the exemptions specified in paragraph (d)(3)(ii)(A) and (B) of this section apply.

(A) Except for pressure relief devices subject to § 63.165(e)(4), equipment such as low leg drains and equipment subject to the requirements of subpart H of this part are not subject to this paragraph (d).

(B) Open-ended valves or lines that use a cap, blind flange, plug, or second valve and follow the requirements specified in § 60.482–6(a)(2), (b), and (c) or follow requirements codified in another regulation that are the same as § 60.482–6(a)(2), (b), and (c) are not subject to this paragraph (d).

* * * * *

■ 70. Amend § 63.128 by:

■ a. Revising and republishing paragraphs (a)(9) and (10);

■ b. Adding paragraph (a)(12); and

■ c. Revising paragraphs (b) introductory text, (c)(2) and (7), (f)(2), and (h)(1)(iv).

The revisions, addition, and republications read as follows:

§ 63.128 Transfer operations provisions—test methods and procedures.

(a) * * *

(9) For the purpose of determining compliance with the 20 parts per million by volume limit in § 63.126(b)(1), Method 18 or Method 25A of appendices A–6 and A–7 to part 60 of this chapter, respectively, shall be used to measure either organic compound concentration or organic HAP concentration, except as provided in paragraphs (a)(11) and (12) of this section.

(i) If Method 25A of appendix A–7 to part 60 of this chapter is used, the following procedures shall be used to calculate the concentration of organic compounds (C_T):

(A) The principal organic HAP in the vent stream shall be used as the calibration gas.

(B) The span value for Method 25A of appendix A–7 to part 60 of this chapter shall be between 1.5 and 2.5 times the concentration being measured.

(C) Use of Method 25A of appendix A–7 to part 60 of this chapter 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.

(D) The concentration of TOC shall be corrected to 3 percent oxygen using the procedures and equation in paragraph (a)(9)(v) of this section.

(ii) If Method 18 of appendix A–6 to 40 CFR part 60 is used to measure the concentration of organic compounds or ASTM D6420–18 (incorporated by reference, see § 63.14), the organic compound concentration (CT) is the sum of the individual components and shall be computed for each run using the following equation:

Equation 1 to Paragraph (a)(9)(ii)

$$C_T = \sum_{j=1}^{n} C_j$$

Where:

C_T = Total concentration of organic compounds (minus methane and ethane), dry basis, parts per million by volume.

C_j = Concentration of sample components j, dry basis, parts per million by volume.

n = Number of components in the sample.

(iii) If an owner or operator uses Method 18 of appendix A–6 to 40 CFR part 60 or ASTM D6420–18 (incorporated by reference, see § 63.14) to compute total organic HAP concentration rather than organic compounds concentration, the equation in paragraph (a)(9)(ii) of this section shall be used except that only organic HAP species shall be summed. The list of organic HAP's is provided in table 2 to subpart F of this part.

(iv) Method 3A of appendix A–2 to 40 CFR part 60 or the manual method in ANSI/ASME PTC 19.10–1981 (incorporated by reference, see § 63.14) shall be used to determine the oxygen concentration. The sampling site shall be the same as that of the organic hazardous air pollutants or organic compound samples, and the samples shall be taken during the same time that the organic hazardous air pollutants or organic compound samples are taken.

(v) The organic compound concentration corrected to 3 percent oxygen (Cc) shall be calculated using the following equation:

Equation 2 to Paragraph (a)(9)(v)

$$C_c = C_T \left(\frac{17.9}{20.9 - \%O_{2d}} \right)$$

Where:

Cc = Concentration of organic compounds corrected to 3 percent oxygen, dry basis, parts per million by volume.

C_T = Total concentration of organic compounds, dry basis, parts per million by volume.

%O2d = Concentration of oxygen, dry basis, percent by volume.

(10) For the purpose of determining compliance with the 98-percent reduction requirement in § 63.126(b)(1), Method 18 or Method 25A of appendices A–6 and A–7 to part 60 of this chapter, respectively, shall be used, except as provided in paragraphs (a)(11) and (12) of this section.

(i) For the purpose of determining compliance with the reduction efficiency requirement, organic compound concentration may be measured in lieu of organic HAP concentration.

(ii) If Method 25A of appendix A–7 to part 60 of this chapter is used to measure the concentration of organic compounds (C_T), the principal organic HAP in the vent stream shall be used as the calibration gas.

(A) An emission testing interval shall consist of each 15-minute period during the performance test. For each interval, a reading from each measurement shall be recorded.

(B) The average organic compound concentration and the volume measurement shall correspond to the same emissions testing interval.

(C) The mass at the inlet and outlet of the control device during each testing interval shall be calculated as follows:

Equation 3 to Paragraph (a)(10)(ii)(C)

$Mj = FKVs\ C_T$

Where:

Mj = Mass of organic compounds emitted during testing interval j, kilograms.

Vs = Volume of air-vapor mixture exhausted at standard conditions, 20 °C and 760 millimeters mercury, standard cubic meters.

C_T = Total concentration of organic compounds (as measured) at the exhaust vent, parts per million by volume, dry basis.

K = Density, kilograms per standard cubic meter organic HAP. 659 kilograms per standard cubic meter organic HAP. (Note: The density term cancels out when the percent reduction is calculated. Therefore, the density used has no effect. The density of hexane is given so that it can be used to maintain the units of Mj.)

F = 10^{-6} = Conversion factor, (cubic meters organic HAP per cubic meters air) * (parts per million by volume)$^{-1}$.

(D) The organic compound mass emission rates at the inlet and outlet of the control device shall be calculated as follows:

Equations 4 and 5 to Paragraph (a)(10)(ii)(D)

$$E_i = \frac{\sum_{j=1}^{n} M_{ij}}{T}$$

$$E_o = \frac{\sum_{j=1}^{n} M_{oj}}{T}$$

Where:

E_i, E_o = Mass flow rate of organic compounds at the inlet (i) and outlet (o) of the combustion or recovery device, kilograms per hour.

M_{ij}, M_{oj} = Mass of organic compounds at the inlet (i) or outlet (o) during testing interval j, kilograms.
T = Total time of all testing intervals, hours.
n = Number of testing intervals.

(iii) If Method 18 of appendix A–6 to 40 CFR part 60 or ASTM D6420–18 (incorporated by reference, see § 63.14) is used to measure organic compounds, the mass rates of organic compounds (Ei, Eo) shall be computed using the following equations:

Equations 6 and 7 to Paragraph (a)(10)(iii)

$$E_i = K_2\left(\sum_{j=1}^{n} C_{ij} MW_{ij}\right)Q_i$$

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj} MW_{oj}\right)Q_o$$

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, parts per million by volume.
MW_{ij}, MW_{oj} = Molecular weight of sample component j of the gas stream at the inlet and outlet of the control device, respectively, gram/gram-mole.
Q_i, Q_o = Flow rate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.
K_2 = Constant, 2.494×10^{-6} (parts per million)$^{-1}$ (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature for (gram-mole per standard cubic meter) is 20 °C.

(iv) Where Method 18 or 25A of appendices A–6 and A–7 to part 60 of this chapter, respectively, or ASTM D6420–18 (incorporated by reference, see § 63.14) is used to measure the percent reduction in organic compounds, the percent reduction across the control device shall be calculated as follows:

Equation 8 to Paragraph (a)(10)(iv)

$$R = \frac{E_i - E_o}{E_i}(100)$$

Where:

R = Control efficiency of control device, percent.
E_i = Mass emitted or mass flow rate of organic compounds at the inlet to the combustion or recovery device as calculated under paragraph (a)(10)(ii)(D) or (a)(10)(iii) of this section, kilogram per hour.
E_o = Mass emitted or mass flow rate of organic compounds at the outlet of the combustion or recovery device, as calculated under paragraph (a)(10)(ii)(D) or (a)(10)(iii) of this section, kilogram per hour.

* * * * *

(12) ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18 of appendix A–6 to part 60 of this chapter, if the target compounds are all known and are all listed in section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method.

(b) Except as specified in § 63.108(a), when a flare is used to comply with § 63.126(b)(2), the owner or operator shall comply with paragraphs (b)(1) through (3) of this section. The owner or operator is not required to conduct a performance test to determine percent emission reduction or outlet organic HAP or TOC concentration.

* * * * *

(c) * * *

(2) When a boiler or process heater burning hazardous waste is used for which the owner or operator:

(i) Has been issued a final permit under part 270 of this chapter and complies with the requirements of part 266, subpart H, of this chapter;

(ii) Has certified compliance with the interim status requirements of part 266, subpart H, of this chapter;

(iii) Has submitted a Notification of Compliance under § 63.1207(j) and complies with the requirements of subpart EEE of this part; or

(iv) Complies with subpart EEE of this part and will submit a Notification of Compliance under § 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

* * * * *

(7) When a hazardous waste incinerator is used for which the owner or operator:

(i) Has been issued a final permit under part 270 of this chapter and complies with the requirements of part 264, subpart O, of this chapter;

(ii) Has certified compliance with the interim status requirements of part 265, subpart O, of this chapter;

(iii) Has submitted a Notification of Compliance under § 63.1207(j) and complies with the requirements subpart EEE of this part; or

(iv) Complies with the requirements subpart EEE of this part and will submit a Notification of Compliance under § 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

* * * * *

(f) * * *

(2) A pressure measurement device which has a precision of ±2.5 millimeters of mercury or better and which is capable of measuring above the pressure at which the tank truck or railcar is to be tested for vapor tightness.

(h) * * *

(1) * * *

(iv) Except as provided in § 63.127(b)(4), for carbon adsorbers, the design evaluation shall include the affinity of the organic HAP vapors for carbon, the amount of carbon in each bed, the number of beds, the humidity of the feed gases, the temperature of the feed gases, the flow rate of the organic HAP emission stream, the desorption schedule, the regeneration stream pressure or temperature, and the flow rate of the regeneration stream. For vacuum desorption, pressure drop shall be included.

* * * * *

■ 71. Amend § 63.129 by revising paragraphs (a)(2), (a)(5) introductory text and (d) to read as follows:

§ 63.129 Transfer operations provisions—reporting and recordkeeping for performance tests and notification of compliance status.

(a) * * *

(2) Include the data specified in paragraphs (a)(4) through (a)(7) of this section in the Notification of Compliance Status report as specified in § 63.152(b) of this subpart. If the performance test report is submitted electronically through the EPA's CEDRI in accordance with § 63.152(h), the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the notification of compliance status report in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the notification of compliance status report is submitted.

* * * * *

(5) Except as specified in paragraph (a) of § 63.108, record and report the following when using a flare to comply with § 63.126(b)(2):

* * * * *

(d) Each owner or operator shall maintain a record describing in detail the vent system used to vent each affected transfer vent stream to a control device. This document shall list all valves and vent pipes that could vent the stream to the atmosphere, thereby bypassing the control device; identify which valves are secured by car-seals or lock-and-key type configurations; and indicate the position (open or closed) of those valves which have car-seals.

Except as specified in paragraph (d)(1) of this section, equipment leaks such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and pressure relief valves needed for safety purposes are not subject to this paragraph.

(1) For each source as defined in § 63.101, on and after July 15, 2027, the last sentence in paragraph (d) of this section no longer applies. Instead, the exemptions specified in paragraph (d)(1)(i) and (d)(1)(ii) of this section apply.

(i) Except for pressure relief devices subject to § 63.165(e)(4) of subpart H of this part, equipment such as low leg drains and equipment subject to the requirements of subpart H of this part are not subject to this paragraph (d) of this section.

(ii) Open-ended valves or lines that use a cap, blind flange, plug, or second valve and follow the requirements specified in 40 CFR 60.482–6(a)(2), (b), and (c) or follow requirements codified in another regulation that are the same as 40 CFR 60.482–6(a)(2), (b), and (c) are not subject to this paragraph (d) of this section.

(2) [Reserved]

* * * * *

■ 72. Amend § 63.130 by:
■ a. Revising paragraph (a)(1);
■ b. Revising and publishing paragraphs (a)(2) and (b);
■ c. Revising paragraph (c); and
■ d. Revising and republishing paragraph (d).

The revisions and republications read as follows:

§ 63.130 Transfer operations provisions—periodic recordkeeping and reporting.

(a) * * *

(1) While the transfer vent stream is being vented to the control device, continuous records of the equipment operating parameters specified to be monitored under § 63.127, and listed in table 7 of this subpart or specified by the Administrator in accordance with §§ 63.127(c) and 63.129(b). For flares complying with§ 63.11(b), the hourly records and records of pilot flame outages specified in table 7 shall be maintained in place of continuous records. For flares complying with § 63.108, the owner or operator must comply with the recordkeeping requirements specified therein.

(2) Records of the daily average value of each monitored parameter for each operating day determined according to the procedures specified in § 63.152(f), except as provided in paragraphs (a)(2)(i) through (a)(2)(iv) of this section.

(i) For flares, except as specified in paragraph (a) of § 63.108, records of the times and duration of all periods during which the pilot flame is absent shall be kept rather than daily averages.

(ii) If carbon adsorber regeneration stream flow and carbon bed regeneration temperature are monitored, the records specified in table 7 to this subpart shall be kept instead of the daily averages.

(iii) Except as specified in paragraph (a)(2)(iv) of this section, records of the duration of all periods when the vent stream is diverted through bypass lines shall be kept rather than daily averages.

(iv) For each flow event from a bypass line subject to the requirements in § 63.127(d) for each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), the owner or operator must also maintain records sufficient to determine whether or not the detected flow included flow requiring control. For each flow event from a bypass line requiring control that is released either directly to the atmosphere or to a control device not meeting the requirements in this subpart, the owner or operator must 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.

* * * * *

(b) If a vapor collection system containing valves that could divert the emission stream away from the control device is used, each owner or operator of a Group 1 transfer rack subject to the provisions of § 63.127(d) shall keep up-to-date, readily accessible records of:

(1) Hourly records of whether the flow indicator specified under § 63.127(d)(1) was operating and whether a diversion was detected at any time during the hour, as well as records of the times of all periods when the vent stream is diverted from the control device or the flow indicator is not operating.

(2) Where a seal mechanism is used to comply with § 63.127(d)(2), hourly records of flow are not required. In such cases, the owner or operator shall record that the monthly visual inspection of the seals or closure mechanisms has been done, and shall record the occurrence of all periods when the seal mechanism is broken, the bypass line valve position has changed, or the key for a lock-and-key type lock has been checked out, and records of any car-seal that has broken, as listed in table 7 of this subpart.

(3) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), the owner or operator must comply with this paragraph in addition to the requirements in paragraphs (b)(1) and (b)(2) of this section. For each flow event from a bypass line subject to the requirements in § 63.127(d), the owner or operator must maintain records sufficient to determine whether or not the detected flow included flow requiring control. For each flow event from a bypass line requiring control that is released either directly to the atmosphere or to a control device not meeting the requirements in this subpart, the owner or operator must 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.

(c) Except as specified in paragraph (a) of § 63.108, each owner or operator of a Group 1 transfer rack who uses a flare to comply with § 63.126(b)(2) shall keep up-to-date, readily accessible records of the flare pilot flame monitoring specified under § 63.127(a)(2).

(d) Each owner or operator of a transfer rack subject to the requirements of § 63.126 shall submit to the Administrator Periodic Reports of the following information according to the schedule in § 63.152(c):

(1) Reports of daily average values of monitored parameters for all operating days when the daily average values were outside the range established in the Notification of Compliance Status or operating permit. Additionally, report the identification of the transfer rack, the monitored parameter out of range, and the date of such occurrences.

(2) Reports of the start date and duration (in hours) of periods when monitoring data are not collected for each excursion caused by insufficient monitoring data as defined in § 63.152(c)(2)(ii)(A).

(3) Reports of the start date and time and duration (in hours) of all periods recorded under paragraph (b)(1) of this section when the vent stream was diverted from the control device, and if applicable, the information in paragraph (d)(7) of this section.

(4) Reports of the start date and time and duration (in hours) recorded under paragraph (b)(2) of this section when maintenance is performed on car-sealed valves, when the car seal is broken, when the bypass line valve position is changed, or the key for a lock-and-key type configuration has been checked out, and if applicable, the information in paragraph (d)(7) of this section.

(5) Except as specified in paragraph (a) of § 63.108, reports of the times and durations of all periods recorded under

paragraph (a)(2)(i) of this section in which all pilot flames of a flare were absent.

(6) Reports of all carbon bed regeneration cycles during which the parameters recorded under paragraph (a)(2)(ii) of this section were outside the ranges established in the Notification of Compliance Status or operating permit. Include the identification of the carbon bed, the monitored parameter that was outside the established range, and the start date, start time, and duration (in hours) for the regeneration cycle in the report.

(7) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), the owner or operator must comply with this paragraph in addition to the requirements in paragraphs (d)(3) and (d)(4) of this section. For bypass lines subject to the requirements in § 63.127(d), the Periodic Report must include the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of organic HAP in the gas in parts per million by volume and the resulting mass emissions of organic HAP in pounds that bypass a control device. For periods when the flow indicator is not operating, report the start date, start time, and duration in hours.

* * * * *

■ 73. Amend § 63.132 by:

■ a. Revising paragraphs (a)(2)(i), (b)(3)(i), and (c)(1);

■ b. Revising and republishing paragraph (d);

■ c. Revising paragraph (f)(2); and

■ d. Adding paragraph (f)(5).

The revisions, addition and republication read as follows:

§ 63.132 Process wastewater provisions—general.

(a) * * *

(2) * * *

(i) Comply with the applicable requirements for wastewater tanks, surface impoundments, containers, individual drain systems, and oil/water separators as specified in § 63.133 through § 63.137 of this subpart, except as provided in paragraphs (a)(2)(i)(A) through (a)(2)(i)(C) of this section and § 63.138(a)(3).

(A) Except as specified in paragraph (a)(2)(i)(C) of this section, the waste management units may be equipped with pressure relief devices that vent directly to the atmosphere provided the pressure relief device is not used for planned or routine venting of emissions.

(B) Except as specified in paragraph (a)(2)(i)(C) of this section, the pressure relief device remains in a closed position at all times except when it is necessary for the pressure relief device to open for the purpose of preventing physical damage or permanent deformation of the waste management unit in accordance with good engineering and safety practices.

(C) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), paragraphs (a)(2)(i)(A) and (a)(2)(i)(B) of this section do not apply. Instead, pressure relief devices are subject to the requirements specified in § 63.165(e) of subpart H of this part.

* * * * *

(b) * * *

(3) * * *

(i) Comply with the applicable requirements for wastewater tanks, surface impoundments, containers, individual drain systems, and oil/water separators specified in the requirements of § 63.133 through § 63.137 of this subpart, except as provided in paragraphs (b)(3)(i)(A) through (b)(3)(i)(C) of this section and § 63.138(a)(3) of this subpart.

(A) Except as specified in paragraph (b)(3)(i)(C) of this section, the waste management units may be equipped with pressure relief devices that vent directly to the atmosphere provided the pressure relief device is not used for planned or routine venting of emissions.

(B) Except as specified in paragraph (b)(3)(i)(C) of this section, the pressure relief device remains in a closed position at all times except when it is necessary for the pressure relief device to open for the purpose of preventing physical damage or permanent deformation of the waste management unit in accordance with good engineering and safety practices.

(C) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), paragraphs (b)(3)(i)(A) and (b)(3)(i)(B) of this section do not apply. Instead, pressure relief devices are subject to the requirements specified in § 63.165(e).

* * * * *

(c) * * *

(1) A wastewater stream is a Group 1 wastewater stream for Table 9 compounds if:

(i) The total annual average concentration of Table 9 compounds is greater than or equal to 10,000 parts per million by weight at any flow rate;

(ii) The total annual average concentration of Table 9 compounds is greater than or equal to 1,000 parts per million by weight and the annual average flow rate is greater than or equal to 10 liters per minute; or

(iii) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(11), the process wastewater stream contains ethylene oxide such that it is considered to be in ethylene oxide service, as defined in § 63.101.

* * * * *

(d) *How to determine Group 1 or Group 2 status for Table 8 compounds.* This paragraph provides instructions for determining whether a wastewater stream is Group 1 or Group 2 for Table 8 compounds. Annual average concentration for each Table 8 compound shall be determined according to the procedures specified in § 63.144(b). Annual average flow rate shall be determined according to the procedures specified in § 63.144(c).

(1) A wastewater stream is a Group 1 wastewater stream for Table 8 compounds if:

(i) The annual average flow rate is 0.02 liter per minute or greater and the annual average concentration of any individual table 8 compound is 10 parts per million by weight or greater; or

(ii) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(11), the process wastewater stream contains ethylene oxide such that it is considered to be in ethylene oxide service, as defined in § 63.101.

(2) A wastewater stream is a Group 2 wastewater stream for Table 8 compounds if it does not meet the criteria specified in paragraph (d)(1)(ii) of this section, and the annual average flow rate is less than 0.02 liter per minute or the annual average concentration for each individual Table 8 compound is less than 10 parts per million by weight.

(3) The owner or operator of a Group 2 wastewater shall re-determine group status for each Group 2 stream, as necessary, to determine whether the stream is Group 1 or Group 2 whenever process changes are made that could reasonably be expected to change the stream to a Group 1 stream. Examples of process changes include, but are not limited to, changes in production capacity, production rate, feedstock type, or whenever there is a replacement, removal, or addition of recovery or control equipment. For purposes of this paragraph (d)(3), process changes do not include: Process upsets; unintentional, temporary process changes; and changes that are within the range on which the original determination was based.

* * * * *

(f) * * *

(2) Except as specified in paragraph (f)(5) of this sections, activities included

in maintenance or startup/shutdown/malfunction plans;

* * * * *

(5) For each source as defined in § 63.101, on and after July 15, 2027, the phrase ''or startup/shutdown/malfunction'' in paragraph (f)(2) of this section does not apply.

* * * * *

■ 74. Amend § 63.133 by revising paragraphs (a)(2)(i), (b) introductory text, (b)(3) and (b)(4) to read as follows:

§ 63.133 Process wastewater provisions—wastewater tanks.

(a) * * *

(2) * * *

(i) A fixed roof and a closed vent system that routes the organic hazardous air pollutants vapors vented from the wastewater tank to a control device.

* * * * *

(b) If the owner or operator elects to comply with the requirements of paragraph (a)(2)(i) of this section, the fixed roof shall meet the requirements of paragraph (b)(1) of this section, the control device shall meet the requirements of paragraph (b)(2) of this section, and the closed vent system shall meet the requirements of paragraph (b)(3) of this section.

* * * * *

(3) Except as provided in paragraph (b)(4) of this section, the closed vent system shall be inspected in accordance with the requirements of § 63.148.

(4) For any fixed roof tank and closed vent system that is operated and maintained under negative pressure, the owner or operator is not required to comply with the requirements specified in § 63.148.

* * * * *

■ 75. Amend § 63.134 by revising paragraphs (b) introductory text, (b)(4) and (b)(5) to read as follows:

§ 63.134 Process wastewater provisions—surface impoundments.

* * * * *

(b) The owner or operator shall operate and maintain on each surface impoundment either a cover (*e.g.,* air-supported structure or rigid cover) and a closed vent system that routes the organic hazardous air pollutants vapors vented from the surface impoundment to a control device in accordance with paragraph (b)(1) of this section, or a floating flexible membrane cover as specified in paragraph (b)(2) of this section.

* * * * *

(4) Except as provided in paragraph (b)(5) of this section, the closed vent system shall be inspected in accordance with § 63.148.

(5) For any cover and closed vent system that is operated and maintained under negative pressure, the owner or operator is not required to comply with the requirements specified in § 63.148.

* * * * *

■ 76. Amend § 63.135 by revising paragraph (b)(3), adding paragraph (b)(4), and revising paragraphs (d) introductory text, (d)(3) and (d)(4) to read as follows:

§ 63.135 Process wastewater provisions—containers.

* * * * *

(b) * * *

(3) Except as specified in paragraph (b)(4) of this section, the cover and all openings shall be maintained in a closed position (*e.g.,* covered by a lid) at all times that a Group 1 wastewater stream or residual removed from a Group 1 wastewater stream is in the container except when it is necessary to use the opening for filling, removal, inspection, sampling, or pressure relief events related to safety considerations.

(4) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), pressure relief devices are subject to the requirements specified in § 63.165(e) of subpart H of this part.

* * * * *

(d) During treatment of a Group 1 wastewater stream or residual removed from a Group 1 wastewater stream, including aeration, thermal or other treatment, in a container, whenever it is necessary for the container to be open, the container shall be located within an enclosure with a closed vent system that routes the organic hazardous air pollutants vapors vented from the container to a control device.

* * * * *

(3) Except as provided in paragraph (d)(4) of this section, the closed vent system shall be inspected in accordance with § 63.148 of this subpart.

(4) For any enclosure and closed vent system that is operated and maintained under negative pressure, the owner or operator is not required to comply with the requirements specified in § 63.148 of this subpart.

* * * * *

■ 77. Amend § 63.136 by revising paragraphs (b)(3) and (4) to read as follows:

§ 63.136 Process wastewater provisions—individual drain systems.

* * * * *

(b) * * *

(3) Except as provided in paragraph (b)(4) of this section, the closed vent system shall be inspected in accordance with § 63.148.

(4) For any cover and closed vent system that is operated and maintained under negative pressure, the owner or operator is not required to comply with the requirements specified in § 63.148.

* * * * *

■ 78. Amend § 63.137 by revising paragraphs (a)(1), (b) introductory text, (b)(3) and (4) to read as follows:

§ 63.137 Process wastewater provisions—oil-water separators.

(a) * * *

(1) A fixed roof and a closed vent system that routes the organic hazardous air pollutants vapors vented from the oil-water separator to a control device. The fixed roof, closed vent system, and control device shall meet the requirements specified in paragraph (b) of this section;

* * * * *

(b) If the owner or operator elects to comply with the requirements of paragraphs (a)(1) or (a)(2) of this section, the fixed roof shall meet the requirements of paragraph (b)(1) of this section, the control device shall meet the requirements of paragraph (b)(2) of this section, and the closed vent system shall meet the requirements of paragraph (b)(3) of this section.

* * * * *

(3) Except as provided in paragraph (b)(4) of this section, the closed vent system shall be inspected in accordance with the requirements of § 63.148.

(4) For any fixed roof and closed vent system that is operated and maintained under negative pressure, the owner or operator is not required to comply with the requirements of § 63.148.

* * * * *

■ 79. Amend § 63.138 by:

■ a. Revising paragraph (b) introductory text and adding paragraph (b)(3);

■ b. Revising paragraph (c) introductory text and adding paragraph (c)(3); and

■ c. Revising paragraphs (h)(1) and (2).

The revisions and additions read as follows:

§ 63.138 Process wastewater provisions—performance standards for treatment processes managing Group 1 wastewater streams and/or residuals removed from Group 1 wastewater streams.

* * * * *

(b) *Control options: Group 1 wastewater streams for Table 9 compounds.* The owner or operator shall comply with either paragraph (b)(1) or (b)(2) of this section, and paragraph (b)(3) of this section, if applicable, for the control of Table 9 compounds at new or existing sources.

* * * * *

(3) *1 ppmw ethylene oxide concentration.* Reduce, by removal or destruction, the concentration of ethylene oxide to a level less than 1 parts per million by weight as determined in the procedures specified in § 63.145(b) of this subpart.

(c) *Control options: Group 1 wastewater streams for Table 8 compounds.* The owner or operator shall comply with either paragraph (c)(1) or (c)(2) of this section, and paragraph (c)(3) of this section, if applicable, for the control of Table 8 compounds at new sources.

* * * * *

(3) *1 ppmw ethylene oxide concentration.* Reduce, by removal or destruction, the concentration of ethylene oxide to a level less than 1 parts per million by weight as determined in the procedures specified in § 63.145(b).

* * * * *

(h) * * *

(1) The wastewater stream or residual is discharged to a hazardous waste incinerator for which the owner or operator:

(i) Has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O;

(ii) Has certified compliance with the interim status requirements of 40 CFR part 265, subpart O;

(iii) Has submitted a Notification of Compliance under § 63.1207(j) and complies with the requirements subpart EEE of this part; or

(iv) Complies with the requirements subpart EEE of this part and will submit a Notification of Compliance under § 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

(2) The wastewater stream or residual is discharged to a process heater or boiler burning hazardous waste for which the owner or operator:

(i) Has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H;

(ii) Has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(iii) Has submitted a Notification of Compliance under § 63.1207(j) and complies with the requirements of subpart EEE of this part; or

(iv) Complies with subpart EEE of this part and will submit a Notification of Compliance under § 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

* * * * *

■ 80. Amend § 63.139 by revising paragraphs (c) and (d) to read as follows:

§ 63.139 Process wastewater provisions—control devices.

* * * * *

(c) The control device shall be designed and operated in accordance with paragraph (c)(1), (2), (3), (4), or (5) of this section.

(1) An enclosed combustion device (including but not limited to a vapor incinerator, boiler, or process heater) shall meet the conditions in paragraph (c)(1)(i), (ii), or (iii) of this section, alone or in combination with other control devices. If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(i) Reduce the total organic compound emissions, less methane and ethane, or total organic hazardous air pollutants emissions vented to the control device by 95 percent by weight or greater;

(ii) Achieve an outlet total organic compound concentration, less methane and ethane, or total organic hazardous air pollutants concentration of 20 parts per million by volume on a dry basis corrected to 3 percent oxygen. The owner or operator shall use either Method 18 of appendix A–6 to part 60 of this chapter, any other method or data that has been validated according to the applicable procedures in Method 301 of appendix A of this part, or ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method; or

(iii) Provide a minimum residence time of 0.5 seconds at a minimum temperature of 760 °C.

(2) A vapor recovery system (including but not limited to a carbon adsorption system or condenser), alone or in combination with other control devices, shall reduce the total organic compound emissions, less methane and ethane, or total organic hazardous air pollutants emissions vented to the control device of 95 percent by weight or greater or achieve an outlet total organic compound concentration, less methane and ethane, or total organic hazardous air pollutants concentration of 20 parts per million by volume. The 20 parts per million by volume performance standard is not applicable to compliance with the provisions of § 63.134 or § 63.135.

(3) Except as specified in paragraph (a) of § 63.108, a flare shall comply with the requirements of § 63.11(b).

(4) A scrubber, alone or in combination with other control devices, shall reduce the total organic compound emissions, less methane and ethane, or total organic hazardous air pollutants emissions in such a manner that 95 weight-percent is either removed, or destroyed by chemical reaction with the scrubbing liquid or achieve an outlet total organic compound concentration, less methane and ethane, or total organic hazardous air pollutants concentration of 20 parts per million by volume. The 20 parts per million by volume performance standard is not applicable to compliance with the provisions of § 63.134 or § 63.135.

(5) Any other control device used shall, alone or in combination with other control devices, reduce the total organic compound emissions, less methane and ethane, or total organic hazardous air pollutants emissions vented to the control device by 95 percent by weight or greater or achieve an outlet total organic compound concentration, less methane and ethane, or total organic hazardous air pollutants concentration of 20 parts per million by volume. The 20 parts per million by volume performance standard is not applicable to compliance with the provisions of § 63.134 or § 63.135.

(d) Except as provided in paragraphs (d)(4) and (5) of this section, an owner or operator shall demonstrate that each control device or combination of control devices achieves the appropriate conditions specified in paragraph (c) of this section by using one or more of the methods specified in paragraphs (d)(1), (2), or (3) of this section.

(1) Performance tests conducted using the test methods and procedures specified in § 63.145(i) for control devices other than flares; or

(2) A design evaluation that addresses the vent stream characteristics and control device operating parameters specified in paragraphs (d)(2)(i) through (vii) of this section.

(i) For a thermal vapor incinerator, the design evaluation shall consider the vent stream composition, constituent concentrations, and flow rate and shall establish the design minimum and average temperature in the combustion zone and the combustion zone residence time.

(ii) For a catalytic vapor incinerator, the design evaluation shall consider the vent stream composition, constituent concentrations, and flow rate and shall establish the design minimum and average temperatures across the catalyst bed inlet and outlet.

(iii) For a boiler or process heater, the design evaluation shall consider the vent stream composition, constituent concentrations, and flow rate; shall establish the design minimum and average flame zone temperatures and combustion zone residence time; and shall describe the method and location where the vent stream is introduced into the flame zone.

(iv) For a condenser, the design evaluation shall consider the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature and shall establish the design outlet organic compound 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.

(v) 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 evaluation shall consider the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for carbon beds, design total regeneration stream mass or volumetric flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of carbon.

(vi) 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 evaluation shall consider the vent stream composition, constituent concentrations, mass or volumetric flow rate, relative humidity, and temperature and shall 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.

(vii) For a scrubber, the design evaluation shall consider the vent stream composition; constituent concentrations; liquid-to-vapor ratio; scrubbing liquid flow rate and concentration; temperature; and the reaction kinetics of the constituents with the scrubbing liquid. The design evaluation shall establish the design exhaust vent stream organic compound concentration level and will include the additional information in paragraphs (d)(2)(vii)(A) and (B) of this section for trays and a packed column scrubber.

(A) Type and total number of theoretical and actual trays;

(B) Type and total surface area of packing for entire column, and for individual packed sections if column contains more than one packed section.

(3) For flares, except as specified in paragraph (a) of § 63.108, the compliance determination specified in § 63.11(b) and § 63.145(j) of this subpart.

(4) An owner or operator using any control device specified in paragraphs (d)(4)(i) through (iv) of this section is exempt from the requirements in paragraphs (d)(1) through (3) of this section and from the requirements in § 63.6(f), and from the requirements of paragraph (e) of this section.

(i) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(ii) A boiler or process heater into which the emission stream is introduced with the primary fuel.

(iii) A boiler or process heater burning hazardous waste for which the owner or operator:

(A) Has been issued a final permit under part 270 of this chapter and complies with the requirements of part 266, subpart H of this chapter;

(B) Has certified compliance with the interim status requirements of part 266, subpart H of this chapter;

(C) Has submitted a Notification of Compliance under § 63.1207(j) and complies with the requirements of subpart EEE of this part; or

(D) Complies with subpart EEE of this part and will submit a Notification of Compliance under § 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

(iv) A hazardous waste incinerator for which the owner or operator:

(A) Has been issued a final permit under part 270 of this chapter and complies with the requirements of part 264, subpart O of this chapter;

(B) Has certified compliance with the interim status requirements of part 265, subpart O of this chapter;

(C) Has submitted a Notification of Compliance under § 63.1207(j) and complies with the requirements subpart EEE of this part; or

(D) Complies with the requirements subpart EEE of this part and will submit a Notification of Compliance under § 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

(5) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), if the owner or operator vents emissions through a closed vent system to an adsorber(s) that cannot be regenerated or a regenerative adsorber(s) that is regenerated offsite, then the requirements specified in paragraphs (d)(1) and (2) of this section do not apply. Instead, the owner or operator must install a system of two or more adsorber units in series and comply with the requirements specified in paragraphs (d)(5)(i) through (iii) of this section.

(i) Conduct an initial performance test or design evaluation of the adsorber and establish the breakthrough limit and adsorber bed life.

(ii) Monitor the HAP or total organic compound (TOC) concentration through a sample port at the outlet of the first adsorber bed in series according to the schedule in paragraph (d)(5)(iii)(B) of this section. The owner or operator must measure the concentration of HAP or TOC using either a portable analyzer, in accordance with Method 21 of appendix A–7 to 40 CFR part 60, using methane, propane, isobutylene, or the primary HAP being controlled as the calibration gas or Method 25A of appendix A–7 to 40 CFR part 60, using methane, propane, or the primary HAP being controlled as the calibration gas.

(iii) Comply with paragraph (d)(5)(iii)(A) of this section, and comply with the monitoring frequency according to paragraph (d)(5)(iii)(B) of this section.

(A) The first adsorber in series must be replaced immediately when breakthrough, as defined in § 63.101, is detected between the first and second adsorber. The original second adsorber (or a fresh canister) will become the new first adsorber and a fresh adsorber will become the second adsorber. For purposes of this paragraph, ''immediately'' means within 8 hours of the detection of a breakthrough for adsorbers of 55 gallons or less, and within 24 hours of the detection of a breakthrough for adsorbers greater than 55 gallons. The owner or operator must monitor at the outlet of the first adsorber within 3 days of replacement to confirm it is performing properly.

(B) Based on the adsorber bed life established according to paragraph (d)(5)(i) of this section and the date the adsorbent was last replaced, conduct monitoring to detect breakthrough at least monthly if the adsorbent has more than 2 months of life remaining, at least weekly if the adsorbent has between 2 months and 2 weeks of life remaining, and at least daily if the adsorbent has 2 weeks or less of life remaining.

* * * * *

■ 81. Amend § 63.143 by revising paragraph (c) to read as follows:

§ 63.143 Process wastewater provisions—inspections and monitoring of operations.

* * * * *

(c) If the owner or operator elects to comply with Item 1 in table 12 to this subpart, the owner or operator shall request approval to monitor appropriate parameters that demonstrate proper operation of the biological treatment unit. The request shall be submitted according to the procedures specified in § 63.151(f), and shall include a description of planned reporting and recordkeeping procedures. The owner or operator shall include as part of the submittal the basis for the selected monitoring frequencies and the methods that will be used. The Administrator will specify appropriate reporting and recordkeeping requirements as part of the review of the permit application or by other appropriate means.

* * * * *

■ 82. Amend § 63.144 by adding paragraph (b)(5)(i)(I) to read as follows:

§ 63.144 Process wastewater provisions—test methods and procedures for determining applicability and Group 1/Group 2 determinations (determining which wastewater streams require control).

* * * * *

(b) * * *

(5) * * *

(i) * * *

(I) *Methods for ethylene oxide.* Methods specified in § 63.109(d) for analysis of ethylene oxide in wastewater.

* * * * *

■ 83. Amend § 63.145 by:

■ a. Revising paragraph (a)(3),

■ b. Adding paragraph (a)(10), and

■ c. Revising paragraphs (d)(4), (i) introductory text, (i)(2), (i)(6)(i), and (j) introductory text.

The revisions and additions read as follows:

§ 63.145 Process wastewater provisions—test methods and procedures to determine compliance.

(a) * * *

(3) *Representative process unit operating conditions.* Except as specified in paragraph (a)(10) of this section, compliance shall be demonstrated for representative operating conditions. Operations during periods of startup, shutdown, or malfunction and periods of nonoperation shall not constitute representative conditions. The owner or operator shall record the process information that is necessary to document operating conditions during the test.

* * * * *

(10) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), the requirement of paragraph (a)(3) of this section no longer applies. Instead, owners and operators must comply with the conditions specified in § 63.103(b)(3)(ii) of subpart F of this part.

* * * * *

(d) * * *

(4) *Concentration in vented gas stream exiting the combustion treatment process.* The concentration of table 8 and/or table 9 compounds exiting the combustion treatment process in any vented gas stream shall be determined as provided in this paragraph. Samples may be grab samples or composite samples. Samples shall be taken at approximately 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. Concentration measurements shall be determined using Method 18 of appendix A–6 to 40 CFR part 60. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method. Alternatively, any other test method validated according to the procedures in Method 301 of appendix A to this part may be used.

* * * * *

(i) *Performance tests for control devices other than flares.* This paragraph applies to performance tests that are conducted to demonstrate compliance of a control device with the efficiency limits specified in § 63.139(c). If complying with the 95-percent reduction efficiency requirement, comply with the requirements specified in paragraphs (i)(1) through (i)(9) of this section. If complying with the 20 ppm by volume requirement, comply with the requirements specified in paragraphs (i)(1) through (6) and (9) of this section. The 20 ppm by volume limit or 95-percent reduction efficiency requirement shall be measured as either total organic hazardous air pollutants or as TOC minus methane and ethane. Performance tests must be conducted according to the schedule in § 63.103(b)(1) of subpart F of this part.

* * * * *

(2) *Concentration in gas stream entering or exiting the control device.* The concentration of total organic hazardous air pollutants or TOC in a gas stream shall be determined as provided in this paragraph. Samples may be grab samples or composite samples (*i.e.,* integrated samples). Samples shall be taken at approximately 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. Concentration measurements shall be determined using Method 18 of appendix A–6 to 40 CFR part 60. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method. Alternatively, any other test method validated according to the procedures in Method 301 of appendix A to this part may be used.

* * * * *

(6) * * *

(i) *Oxygen concentration.* The concentration of TOC or total organic hazardous air pollutants shall be corrected to 3 percent oxygen if the control device is a combustion device. Method 3A of appendix A–2 to 40 CFR part 60 or the manual method in ANSI/ASME PTC 19.10–1981 (incorporated by reference, see § 63.14) shall be used to determine the actual oxygen concentration (%02d). The samples shall be taken during the same time that the TOC (minus methane or ethane) or total organic hazardous air pollutants samples are taken.

* * * * *

(j) Except as specified in paragraph (a) of § 63.108, when a flare is used to comply with § 63.139(c), the owner or operator shall comply with paragraphs (j)(1) through (3) of this section. The owner or operator is not required to conduct a performance test to determine percent emission reduction or outlet organic HAP or TOC concentration.

* * * * *

■ 84. Amend § 63.146 by revising paragraphs (b)(7)(i) introductory text, (b)(7)(ii)(C), (b)(9)(ii), and revising and republishing paragraphs (d) and (e) to read as follows:

§ 63.146 Process wastewater provisions—reporting.

* * * * *

(b) * * *

(7) * * *

(i) Except as specified in paragraph (a) of § 63.108, for each flare, the owner or operator shall submit the information specified in paragraphs (b)(7)(i)(A) through (b)(7)(i)(C) of this section.

* * * * *

(ii) * * *

(C) Results of the performance test specified in § 63.139(d)(1) of this subpart. Performance test results shall include operating ranges of key process and control parameters during the performance test; the value of each parameter being monitored in accordance with § 63.143 of this subpart; and applicable supporting calculations. If the performance test report is submitted electronically through the EPA's CEDRI in accordance with § 63.152(h), the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the notification of compliance status report in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the notification of compliance status report is submitted.

* * * * *

(9) * * *

(ii) Results of the performance test specified in § 63.138(j)(2) of this subpart. Performance test results shall include operating ranges of key process and control parameters during the performance test; the value of each parameter being monitored in accordance with § 63.143 of this subpart; and applicable supporting calculations. If the performance test report is submitted electronically through the EPA's CEDRI in accordance with § 63.152(h), the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the notification of compliance status report in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the notification of compliance status report is submitted.

* * * * *

(d) Except as provided in paragraph (f) of this section, for each treatment process used to comply with § 63.138(b)(1), (c)(1), (d), (e), (f), or (g), the owner or operator shall submit as part of the next Periodic Report required by § 63.152(c) the information specified in paragraphs (d)(1), (2), and (3) of this section for the monitoring required by § 63.143(b), (c), and (d).

(1) For Item 1 in table 12, the owner or operator shall submit the results of measurements that indicate that the biological treatment unit is outside the range established in the Notification of Compliance Status or operating permit. Include the identification of the biological treatment unit, the parameter that was out of range and the date that the parameter is out of range.

(2) For Item 2 in table 12, the owner or operator shall submit the monitoring results for each operating day during which the daily average value of a continuously monitored parameter is outside the range established in the Notification of Compliance Status or operating permit. Include the identification of the treatment process, the parameter that was out of range, and the date the parameter was out of range.

(3) For Item 3 in table 12 of this subpart, the owner or operator shall submit the monitoring results for each operating day during which the daily average value of any monitored parameter approved in accordance with § 63.151 (f) was outside the range established in the Notification of Compliance Status or operating permit. Include the identification of the treatment process, the parameter that was out of range, and the date the parameter was out of range.

(e) Except as provided in paragraph (f) of this section, for each control device used to comply with §§ 63.133 through 63.139, the owner or operator shall submit as part of the next Periodic Report required by § 63.152(c) the information specified in either paragraph (e)(1) or (e)(2) of this section.

(1) The information specified in table 20 of this subpart, including the date of each occurrence, or

(2) If the owner or operator elects to comply with § 63.143(e)(2) of this subpart, *i.e.,* an organic monitoring device installed at the outlet of the control device, the owner or operator shall submit the date and the monitoring results for each operating day during which the daily average concentration level or reading is outside the range established in the Notification of Compliance Status or operating permit.

* * * * *

■ 85. Amend § 63.147 by revising and republishing paragraph (d) to read as follows:

§ 63.147 Process wastewater provisions—recordkeeping.

* * * * *

(d) The owner or operator shall keep records of the daily average value of each continuously monitored parameter for each operating day as specified in § 63.152(f), except as provided in paragraphs (d)(1) through (4) of this section.

(1) For flares, except as specified in paragraph (a) of § 63.108, records of the times and duration of all periods during which the pilot flame is absent shall be kept rather than daily averages.

(2) *Regenerative carbon adsorbers.* Except as specified in paragraph (d)(4) of this section, for regenerative carbon adsorbers, the owner or operator shall keep the records specified in paragraphs (d)(2)(i) and (ii) of this section instead of daily averages.

(i) Records of the total regeneration stream mass flow for each carbon bed regeneration cycle.

(ii) Records of the temperature of the carbon bed after each regeneration cycle.

(3) *Non-regenerative carbon adsorbers.* Except as specified in paragraph (d)(4) of this section, for non-regenerative carbon adsorbers using organic monitoring equipment, the owner or operator shall keep the records specified in paragraph (d)(3)(i) of this section instead of daily averages. For non-regenerative carbon adsorbers replacing 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, the owner or operator shall keep the records specified in paragraph (d)(3)(ii) of this section instead of daily averages.

(i)(A) Record of how the monitoring frequency, as specified in table 13 of this subpart, was determined.

(B) Records of when organic compound concentration of adsorber exhaust was monitored.

(C) Records of when the carbon was replaced.

(ii)(A) Record of how the carbon replacement interval, as specified in table 13 of this subpart, was determined.

(B) Records of when the carbon was replaced.

(4) For each nonregenerative adsorber and regenerative adsorber that is regenerated offsite subject to the requirements in § 63.139(d)(5), the owner or operator must keep the applicable records specified in (d)(4)(i) through (d)(4)(iii) of this section.

(i) Breakthrough limit and bed life established according to § 63.139(d)(5)(i).

(ii) Each outlet HAP or TOC concentration measured according to §§ 63.139(d)(5)(ii) and (d)(5)(iii).

(iii) Date and time you last replaced the adsorbent.

* * * * *

■ 86. Amend § 63.148 by:

■ a. Revising paragraphs (a), (b) introductory text, (f) introductory text and (f)(3);
■ b. Adding paragraph (f)(4);
■ c. revising paragraph (i)(3) introductory text and adding paragraph (i)(3)(iii); and
■ d. Revising paragraphs (j) and (k).

The revisions and additions read as follows:

§ 63.148 Leak inspection provisions.

(a) Except as provided in paragraph (k) of this section, for each vapor collection system, closed vent system, fixed roof, cover, or enclosure required to comply with this section, the owner or operator shall comply with the requirements of paragraphs (b) through (j) of this section.

(b) Except as provided in paragraphs (g) and (h) of this section, each vapor collection system and closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (b)(1) and (b)(2) of this section and each fixed roof, cover, and enclosure shall be inspected according to the procedures and schedule specified in paragraph (b)(3) of this section.

* * * * *

(f) For each vapor collection system or closed vent system that contains bypass lines that could divert a vent stream away from the control device and to the atmosphere, the owner or operator shall comply with the provisions of either paragraph (f)(1) or (f)(2), and (f)(4) of this section, except as provided in paragraph (f)(3) of this section.

* * * * *

(3) Except as specified in paragraph (f)(4) of this section, equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and pressure relief valves needed for safety purposes are not subject to this paragraph.

(4) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10):

(i) The use of a bypass line at any time on a closed vent system to divert emissions (subject to the emission suppression requirements specified in §§ 63.133 through 63.137) to the atmosphere or to a control device not meeting the requirements specified in this subpart is an emissions standards violation.

(ii) Paragraph (f)(3) of this section no longer applies. Instead, the exemptions specified in paragraphs (f)(4)(ii)(A) and (f)(4)(ii)(B) of this section apply.

(A) Except for pressure relief devices subject to § 63.165(e)(4), equipment such as low leg drains and equipment subject to the requirements of subpart H of this part are not subject to this paragraph (f) of this section.

(B) Open-ended valves or lines that use a cap, blind flange, plug, or second valve and follow the requirements specified in 40 CFR 60.482–6(a)(2), (b), and (c) or follow requirements codified in another regulation that are the same as 40 CFR 60.482–6(a)(2), (b), and (c) are not subject to this paragraph (f) of this section.

* * * * *

(i) * * *

(3) For each vapor collection system or closed vent system that contains bypass lines that could divert a vent stream away from the control device and to the atmosphere, the owner or operator shall keep a record of the information specified in either paragraph (i)(3)(i) or (i)(3)(ii) of this section in addition to the information specified in paragraph (i)(3)(iii) of this section.

* * * * *

(iii) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), the owner or operator must comply with this paragraph in addition to the requirements in paragraphs (i)(3)(i) or (i)(3)(ii) of this section. For each flow event from a bypass line subject to the requirements in paragraph (f) of this section, the owner or operator must maintain records sufficient to determine whether or not the detected flow included flow requiring control. For each flow event from a bypass line requiring control that is released either directly to the atmosphere or to a control device not meeting the requirements in this subpart, the owner or operator must 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.

* * * * *

(j) The owner or operator shall submit with the reports required by § 63.182(b) of subpart H of this part or with the reports required by § 63.152(c) of this subpart, the information specified in paragraphs (j)(1) through (3) of this section and if applicable, the information in paragraph (j)(4) of this section.

(1) The information specified in paragraph (i)(4) of this section;

(2) Reports of the times of all periods recorded under paragraph (i)(3)(i) of this section when the vent stream is diverted from the control device through a bypass line, including the start date, start time, and duration in hours; and

(3) Reports of all periods recorded under paragraph (i)(3)(ii) of this section in which the seal mechanism is broken, the bypass line valve position has changed, or the key to unlock the bypass line valve was checked out. Include the start date, start time, and duration in hours for each period.

(4) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), the owner or operator must comply with this paragraph in addition to the requirements in paragraphs (j)(1) through (3) of this section. For bypass lines subject to the requirements in paragraph (f) of this section, the Periodic Report must include the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of organic HAP in the gas in parts per million by volume and the resulting mass emissions of organic HAP in pounds that bypass a control device. For periods when the flow indicator is not operating, report the start date, start time, and duration in hours.

(k) If a closed vent system subject to this section is also subject to § 63.172, the owner or operator shall comply with the provisions of § 63.172 and is exempt from the requirements of this section.

■ 87. Amend § 63.150 by revising paragraphs (f)(2), (g)(2)(ii), (g)(2)(iii)(B)(*2*), (m)(1)(ii) and (m)(2)(i) to read as follows:

§ 63.150 Emissions averaging provisions.

* * * * *

(f) * * *

(2) Periods of start-up, shutdown, and malfunction as described in the source's start-up, shutdown, and malfunction plan required by § 63.6(e)(3). For each source as defined in § 63.101, on and after July 15, 2027, this paragraph no longer applies.

* * * * *

(g) * * *

(2) * * *

(ii) The following equation shall be used for each process vent i to calculate EPV_{iu}:

$$EPV_{iu} = (2.494 \times 10^{-9})\, Qh \left(\sum_{j=1}^{n} C_j M_j \right)$$

Where:

EPV_{iu} = Uncontrolled process vent emission rate from process vent i, megagrams per month.
Q = Vent stream flow rate, dry standard cubic meters per minute, measured using Method 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.
Cj = Concentration, parts per million by volume, dry basis, of organic HAP j as measured by Method 18 of part 60, appendix A, or ASTM D6420–18 (incorporated by reference, see § 63.14).
Mj = Molecular weight of organic HAP j, gram per gram-mole.
n = Number of organic HAP's.

(A) The values of Q, C_j, and M_j shall be determined during a performance test conducted under representative operating conditions as specified in § 63.103(b)(3). The values of Q, C_j, and M_j shall be established in the Notification of Compliance Status and must be updated as provided in paragraph (g)(2)(ii)(B) of this section.

* * * * *

(iii) * * *

(B) * * *

(*2*) For determining debits from Group 1 process vents, recovery devices shall not be considered control devices and cannot be assigned a percent reduction in calculating $EPV_{iACTUAL}$. The sampling site for measurement of uncontrolled emissions is after the final recovery device. However, as provided in § 63.113(a)(3), except as specified in § 63.113(a)(4), a Group 1 process vent may add sufficient recovery to raise the TRE index value above 1.0, thereby becoming a Group 2 process vent.

* * * * *

(m) * * *

(1) * * *

(ii) Conduct performance tests to determine percent reduction as specified in § 63.116 of this subpart;

* * * * *

(2) * * *

(i) Except as specified in § 63.113(a)(4), determine, consistent with paragraph (g)(2)(i) of this section, the flow rate, organic HAP concentration, and TRE index value using the methods specified in § 63.115;

* * * * *

■ 88. Amend § 63.151 by revising paragraphs (d)(6)(i) and (d)(6)(v) as follows:

§ 63.151 Initial notification.

* * * * *

(d) * * *

(6) * * *

(i) The values of the parameters used to determine whether the emission point is Group 1 or Group 2. Except as specified in § 63.113(a)(4), where TRE index value is used for process vent group determination, the estimated or measured values of the parameters used in the TRE equation in § 63.115(d) (flow rate, organic HAP emission rate, TOC emission rate, and net heating value) and the resulting TRE index value shall be submitted.

* * * * *

(v) The operating plan required in § 63.122(a)(2) and (b) for each storage vessel controlled with a closed vent system with a control device other than a flare.

* * * * *

■ 89. Amend § 63.152 by:
■ a. Revising paragraph (b)(1)(i);
■ b. Adding paragraphs (b)(7) through (b)(10);
■ c. Revising and republishing paragraph (c);
■ d. Revising paragraphs (d)(1), (f) introductory text and (f)(7) introductory text;
■ e. Adding paragraph (f)(7)(vi);
■ f. Revising and republishing paragraphs (g)(1) and (2); and
■ g. Adding paragraph (h) as follows:

§ 63.152 General reporting and continuous records.

* * * * *

(b) * * *

(1) * * *

(i) For performance tests and group determinations that are based on measurements, the Notification of Compliance Status shall include one complete test report for each test method used for a particular kind of emission point. For additional tests performed for the same kind of emission point using the same method, the results and any other information required in § 63.117 for process vents, § 63.129 for transfer, and § 63.146 for process wastewater shall be submitted, but a complete test report is not required. If the performance test report is submitted electronically through the EPA's CEDRI in accordance with paragraph (h) of this section, the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the notification of compliance status report in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the notification of compliance status report is submitted.

* * * * *

(7) For flares subject to the requirements in § 63.108, owners and operators must also submit the information in this paragraph in a supplement to the Notification of Compliance Status within 150 days after the first applicable compliance date for flare monitoring. The supplement to the Notification of Compliance Status must include flare design (*e.g.,* steam-assisted, air-assisted, non-assisted, or pressure-assisted multi-point); all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the initial visible emissions demonstration required by § 63.670(h) of subpart CC of this part, as applicable; and all periods during the compliance determination when the pilot flame or flare flame is absent.

(8) For process vents and storage vessels subject to the requirements of § 63.124, owners and operators must also submit the information in this paragraph in a supplement to the Notification of Compliance Status within 150 days after the first applicable compliance date. The supplement to the Notification of Compliance Status must identify all process vents and storage vessels that are in ethylene oxide service as defined in § 63.101, the method(s) used to control ethylene oxide emissions from each process vent and storage vessel (*i.e.,* use of a flare, scrubber, or other control device) and the information specified in paragraphs (b)(8)(i) and (b)(8)(ii) of this section, as applicable.

(i) For process vents, all uncontrolled, undiluted ethylene oxide concentration measurements, and the calculations used to determine the total uncontrolled ethylene oxide mass emission rate for the sum of all vent gas streams; and

(ii) For storage vessels, include the concentration of ethylene oxide of the fluid stored in each storage vessel.

(9) For adsorbers subject to the requirements of §§ 63.114(a)(5)(v), 63.120(d)(1)(iii), 63.127(b)(4), and 63.139(d)(5), you must also submit the information listed in paragraphs (b)(9)(i) and (ii) of this section in a supplement

to the Notification of Compliance Status within 150 days after the first applicable compliance date.

(i) Whether the adsorber cannot be regenerated or is a regenerative adsorber(s) that is regenerated offsite.

(ii) The breakthrough limit and adsorber bed life established during the initial performance test or design evaluation of the adsorber.

(10) For Group 2 process vents subject to the requirements in § 63.113(l), owners and operators must also submit the information in this paragraph in a supplement to the Notification of Compliance Status within 150 days after the first applicable compliance date. The supplement to the Notification of Compliance Status must identify each Group 2 process vent and include the data and calculations specified in § 63.115(g) that are used to demonstrate that the total organic HAP mass flow rate of each vent stream is less than 1.0 pound per hour.

(c) The owner or operator of a source subject to this subpart shall submit Periodic Reports. On and after July 15, 2027 or once the reporting template for this subpart has been available on the CEDRI website for 1 year, whichever date is later, owners and operators must submit all subsequent reports following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Hazardous Organic Chemical Manufacturing Sector Lead. Owners and operators must use the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports under § 63.9(i) and § 63.10(a), the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(1) Except as specified under paragraphs (c)(5) and (c)(6) of this section, a report containing the information in paragraphs (c)(2), (c)(3), (c)(4), and (c)(7) of this section shall be submitted semiannually no later than 60 calendar days after the end of each 6-month period. The first report shall be submitted no later than 8 months after the date the Notification of Compliance Status is due and shall cover the 6-month period beginning on the date the Notification of Compliance Status is due. All periodic reports must contain the company name and address (including county), as well as the beginning and ending dates of the reporting period.

(2) Except as provided in paragraph (c)(2)(iv) of this section, for an owner or operator of a source complying with the provisions of §§ 63.113 through 63.147 for any emission points, Periodic Reports shall include all information specified in §§ 63.117 and 63.118 for process vents, § 63.122 for storage vessels, §§ 63.129 and 63.130 for transfer operations, and § 63.146 for process wastewater, including reports of each excursion (*i.e.,* each period when a monitored parameter is outside the established range and periods of insufficient monitoring data) using the procedures described in paragraphs (c)(2)(i) through (c)(2)(iv) of this section.

(i) Report the affected sources or equipment, the monitored parameter that was exceeded and the date of each excursion.

(ii) The parameter monitoring data for Group 1 emission points and emission points included in emissions averages that are required to perform continuous monitoring shall be used to determine compliance with the required operating conditions for the monitored control devices or recovery devices. For each excursion as specified in paragraphs (c)(2)(ii)(A) through (c)(2)(ii)(E) of this section, or paragraph (g)(2)(iv) of this section, except for excused excursions described therein, the owner or operator shall be deemed to have failed to have applied the control in a manner that achieves the required operating conditions and must report the information specified in paragraph (c)(2)(ii)(F) of this section.

(A) An excursion means any of the three cases listed in paragraph (c)(2)(ii)(A)(*1*), (c)(2)(ii)(A)(*2*), or (c)(2)(ii)(A)(*3*) of this section. For a control device or recovery device where multiple parameters are monitored, if one or more of the parameters meets the excursion criteria in paragraph (c)(2)(ii)(A)(*1*), (c)(2)(ii)(A)(*2*), or (c)(2)(ii)(A)(*3*) of this section, this is considered a single excursion for the control device or recovery device.

(*1*) When the daily average value of one or more monitored parameters is outside the permitted range.

(*2*) When the period of control device or recovery device operation is 4 hours or greater in an operating day and monitoring data are insufficient to constitute a valid hour of data for at least 75 percent of the operating hours.

(*3*) When the period of control device or recovery device operation is less than 4 hours in an operating day and more than one of the hours during the period of operation does not constitute a valid hour of data due to insufficient monitoring data.

(*4*) Monitoring data are insufficient to constitute a valid hour of data, as used in paragraphs (c)(2)(ii)(A)(*2*) and (c)(2)(ii)(A)(*3*) of this section, if measured values are unavailable for any of the 15-minute periods within the hour. For data compression systems approved under § 63.151(g)(4), monitoring data are insufficient to calculate a valid hour of data if there are less than 4 data values recorded during the hour.

(B) The number of excused excursions for each control device or recovery device for each semiannual period is specified in paragraphs (c)(2)(ii)(B)(*1*) through (c)(2)(ii)(B)(*6*) of this section. This paragraph applies to sources required to submit Periodic Reports semiannually or quarterly. The first semiannual period is the 6-month period starting the date the Notification of Compliance Status is due.

(*1*) For the first semiannual period—six excused excursions.

(*2*) For the second semiannual period—five excused excursions.

(*3*) For the third semiannual period—four excused excursions.

(*4*) For the fourth semiannual period—three excused excursions.

(*5*) For the fifth semiannual period—two excused excursions.

(*6*) For the sixth and all subsequent semiannual periods—one excused excursion.

(C) A monitored parameter that is outside its established range or monitoring data that are not collected are excursions. However, if the conditions in paragraph (c)(2)(ii)(C)(*1*) or (c)(2)(ii)(C)(*2*) of this section are met, these excursions are not violations and do not count toward the number of excused excursions for determining compliance.

(*1*) *Periods of startup, shutdown, or malfunction.* During periods of startup, shutdown, or malfunction when the source is operated during such periods in accordance with § 63.102(a)(4). For each source as defined in § 63.101, on and after July 15, 2027, this paragraph no longer applies.

(*2*) *Periods of nonoperation.* During periods of nonoperation of the chemical manufacturing process unit, or portion thereof, that results in cessation of the emissions to which the monitoring applies.

(D) Nothing in paragraph (c)(2)(ii) of this section shall be construed to allow or excuse a monitoring parameter excursion caused by any activity that violates other applicable provisions of subpart A, F, or G of this part.

(E) Paragraph (c)(2)(ii) of this section, except paragraph (c)(2)(ii)(C) of this section, shall apply only to emission points and control devices or recovery devices for which continuous monitoring is required by §§ 63.113 through 63.150.

(F) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), for each excursion that is not an excused excursion, the report must include a list of the affected sources or equipment, the monitored parameter for which there was an excursion, the date of the excursion, an estimate of the quantity in pounds of each regulated pollutant emitted over any emission limit, a description of the method used to estimate the emissions, the cause of the excursion (including unknown cause, if applicable), as applicable, and the corrective action taken.

(iii) Periodic Reports shall include the daily average values of monitored parameters for both excused and unexcused excursions, as defined in paragraph (c)(2)(ii)(A) of this section. For excursions caused by lack of monitoring data, the affected equipment or source, the monitored parameter, the start date and duration in hours of periods when monitoring data were not collected shall be specified.

(iv) The provisions of paragraphs (c)(2) of this section, and (c)(2)(i) through (iii) of this section, do not apply to any storage vessel for which the owner or operator is not required, by the applicable monitoring plan established under § 63.120(d)(2), to keep continuous records. If continuous records are required, the owner or operator shall specify, in the monitoring plan, whether the provisions of paragraphs (c)(2) of this section, and (c)(2)(i) through (iii) of this section apply.

(3) Except as specified in paragraph (c)(3)(iii) of this section, if any performance tests are reported in a Periodic Report, the following information shall be included:

(i) One complete test report shall be submitted for each test method used for a particular kind of emission point tested. A complete test report shall contain the information specified in paragraph (b)(1)(ii) of this section.

(ii) For additional tests performed for the same kind of emission point using the same method, results and any other information required in § 63.117 for process vents, § 63.129 for transfer, and § 63.146 for process wastewater shall be submitted, but a complete test report is not required.

(iii) If the performance test report is submitted electronically through the EPA's CEDRI in accordance with paragraph (h) of this section, the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the Periodic Report in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the Periodic Report is submitted.

(4) Periodic Reports shall include the information in paragraphs (c)(4)(i) through (iv) of this section, as applicable:

(i) For process vents, reports of process changes as required under § 63.118(g), (h), (i), and (j),

(ii) Any supplements required under § 63.151(i) and (j),

(iii) Notification if any Group 2 emission point becomes a Group 1 emission point, including a compliance schedule as required in § 63.100, and

(iv) For gas streams sent for disposal pursuant to § 63.113(i) or for process wastewater streams sent for treatment pursuant to § 63.132(g), reports of changes in the identity of the transferee.

(5) 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 no later than 5 months after the compliance date specified in § 63.100.

(ii) The quarterly reports shall include the information specified in this paragraph for all emission points included in an emissions average.

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

(B) A demonstration that debits calculated for the quarter are not more than 1.30 times the credits calculated for the quarter, as required under § 63.150(e)(4).

(C) The values of any inputs to the credit and debit equations in § 63.150(g) and (h) that change from month to month during the quarter or that have changed since the previous quarter;

(D) Results of any performance tests conducted during the reporting period including one complete report for each test method used for a particular kind of emission point as described in paragraph (c)(3) of this section. If the performance test report is submitted electronically through the EPA's CEDRI in accordance with paragraph (h) of this section, the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the Periodic Report in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the Periodic Report is submitted.;

(E) Reports of daily average values of monitored parameters for both excused and unexcused excursions as defined in paragraph (c)(2)(ii)(A) of this section. For excursions caused by lack of monitoring data, the duration of periods when monitoring data were not collected shall be specified. Include the affected sources or equipment, monitored parameter, and the date for each excursion.

(iii) Paragraphs (c)(2)(i) through (iii) of this section shall govern the use of monitoring data to determine compliance for Group 1 and Group 2 points included in emissions averages. For storage vessels to which the provisions of paragraphs (c)(2)(i) through (iii) of this section do not apply (as specified in paragraph (c)(2)(iv) of this section), the owner or operator is required to comply with the provisions of the applicable monitoring plan, and monitoring records may be used to determine compliance.

(iv) 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 § 63.150(e)(3); and

(B) A certification of compliance with all the emissions averaging provisions in § 63.150.

(6) The owner or operator of a source shall submit reports quarterly for particular emission points not included in an emissions average under the circumstances described in paragraphs (c)(6)(i) through (v) of this section.

(i) The owner or operator of a source subject to this subpart shall submit quarterly reports for a period of one year for an emission point that is not included in an emissions average if:

(A) The emission point has more excursions, as defined in paragraph (c)(2)(ii) of this section, than the number of excused excursions allowed under paragraph (c)(2)(ii)(B) of this section for a semiannual reporting period; and

(B) The Administrator requests the owner or operator to submit quarterly reports for the emission point.

(ii) The quarterly reports shall include all information in paragraphs (c)(2), (3), and (4) of this section applicable to the emission point(s) for which quarterly reporting is required under paragraph (c)(6)(i) of this section. Information applicable to other emission points within the source shall be submitted in the semiannual reports required under paragraph (c)(1) of this section.

(iii) Quarterly reports shall be submitted no later than 60 calendar days after the end of each quarter.

(iv) After quarterly reports have been submitted for an emission point for one year, the owner or operator may return to semiannual reporting for the emission point unless the Administrator requests the owner or operator to continue to submit quarterly reports.

(v) Paragraphs (c)(2)(i) through (iii) of this section shall govern the use of monitoring data to determine compliance for Group 1 emission points. For storage vessels to which the provisions of paragraphs (c)(2)(i) through (iii) of this section do not apply (as specified in paragraph (c)(2)(iv) of this section), the owner or operator is required to comply with the provisions of the applicable monitoring plan, and monitoring records may be used to determine compliance.

(7) The information specified in § 63.108(l)(2) of subpart F of this part.

(d) * * *

(1) Reports of start-up, shutdown, and malfunction required by § 63.10(d)(5). The start-up, shutdown and malfunction reports may be submitted on the same schedule as the Periodic Reports required under paragraph (c) of this section instead of the schedule specified in § 63.10(d)(5). For each source as defined in § 63.101, on and after July 15, 2027, this paragraph no longer applies.

* * * * *

(f) Owners or operators required to keep continuous records by §§ 63.118, 63.130, 63.147, 63.150, or other sections of this subpart shall keep records as specified in paragraphs (f)(1) through (f)(7) of this section, unless an alternative recordkeeping system has been requested and approved under § 63.151(f) or (g) or § 63.152(e) or under § 63.8(f), and except as provided in paragraph (c)(2)(ii)(C) of this section or in paragraph (g) of this section. If a monitoring plan for storage vessels pursuant to § 63.120(d)(2)(i) requires continuous records, the monitoring plan shall specify which provisions, if any, of paragraphs (f)(1) through (f)(7) of this section apply. Any records required to be maintained by this part that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

* * * * *

(7) Except as specified in paragraph (f)(7)(vi) of this section monitoring data recorded during periods identified in paragraphs (f)(7)(i) through (f)(7)(v) of this section 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.

* * * * *

(vi) For each source as defined in § 63.101, on and after July 15, 2027, paragraphs (f)(7)(ii) through (f)(7)(iv) no longer apply.

(g) * * *

(1) The owner or operator may retain only the daily average value, and is not required to retain more frequent monitored operating parameter values, for a monitored parameter with respect to an item of equipment, if the requirements of paragraphs (g)(1)(i) through (vi) of this section are met. An owner or operator electing to comply with the requirements of paragraph (g)(1) of this section shall notify the Administrator in the Notification of Compliance Status or, if the Notification of Compliance Status has already been submitted, in the periodic report immediately preceding implementation of the requirements of paragraph (g)(1) of this section.

(i) The monitoring system is capable of detecting unrealistic or impossible data during periods of operation other than startups, shutdowns, or malfunctions (*e.g.,* a temperature reading of −200 °C on a boiler), and will alert the operator by alarm or other means. The owner or operator shall record the occurrence. All instances of the alarm or other alert in an operating day constitute a single occurrence. For each source as defined in § 63.101, on and after July 15, 2027, the phrase ''other than startups, shutdowns, or malfunctions (*e.g.,* a temperature reading of −200 °C on a boiler),'' in this paragraph no longer applies.

(ii) The monitoring system generates, updated at least hourly throughout each operating day, a running average of the monitoring values that have been obtained during that operating day, and the capability to observe this average is readily available to the Administrator on-site during the operating day. The owner or operator shall record the occurrence of any period meeting the criteria in paragraphs (g)(1)(ii)(A) through (C) of this section. All instances in an operating day constitute a single occurrence.

(A) The running average is above the maximum or below the minimum established limits;

(B) The running average is based on at least 6 1-hour average values; and

(C) The running average reflects a period of operation other than a startup, shutdown, or malfunction. For each source as defined in § 63.101, on and after July 15, 2027, the phrase ''other than a startup, shutdown, or malfunction'' in this paragraph no longer applies.

(iii) The monitoring system is capable of detecting unchanging data during periods of operation other than startups, shutdowns, or malfunctions, except in circumstances where the presence of unchanging data is the expected operating condition based on past experience (*e.g.,* pH in some scrubbers), and will alert the operator by alarm or other means. The owner or operator shall record the occurrence. All instances of the alarm or other alert in an operating day constitute a single occurrence. For each source as defined in § 63.101, on and after July 15, 2027, the phrase ''other than startups, shutdowns, or malfunctions'' in this paragraph no longer applies.

(iv) The monitoring system will alert the owner or operator by an alarm or other means, if the running average parameter value calculated under paragraph (g)(1)(ii) of this section reaches a set point that is appropriately related to the established limit for the parameter that is being monitored.

(v) The owner or operator shall verify the proper functioning of the monitoring system, including its ability to comply with the requirements of paragraph (g)(1) of this section, at the times specified in paragraphs (g)(1)(v)(A) through (C) of this section. The owner or operator shall document that the required verifications occurred.

(A) Upon initial installation.

(B) Annually after initial installation.

(C) After any change to the programming or equipment constituting the monitoring system, which might reasonably be expected to alter the monitoring system's ability to comply with the requirements of this section.

(vi) The owner or operator shall retain the records identified in paragraphs (g)(1)(vi)(A) through (C) of this section.

(A) Identification of each parameter, for each item of equipment, for which the owner or operator has elected to comply with the requirements of paragraph (g) of this section.

(B) A description of the applicable monitoring system(s), and of how compliance will be achieved with each requirement of paragraph (g)(1)(i) through (g)(1)(v) of this section. The description shall include monitoring equipment manufacturer(s) and model number(s) and the pollutant or parameter monitored, and identify the location and format (*e.g.,* on-line storage; log entries) for each required record. If the description changes, the owner or operator shall retain both the current and the most recent superseded description. The description, and the most recent superseded description, shall be retained as provided in § 63.103(c) of subpart F of this part, except as provided in paragraph (g)(1)(vi)(D) of this section.

(C) A description, and the date, of any change to the monitoring system that would reasonably be expected to affect its ability to comply with the requirements of paragraph (g)(1) of this section.

(D) Owners and operators subject to paragraph (g)(1)(vi)(B) of this section shall retain the current description of the monitoring system as long as the description is current, but not less than 5 years from the date of its creation. The current description shall, at all times, be retained on-site or be accessible from a central location by computer or other means that provides access within 2 hours after a request. The owner or operator shall retain the most recent superseded description at least until 5 years from the date of its creation. The superseded description shall be retained on-site (or accessible from a central location by computer that provides access within 2 hours after a request) at least 6 months after its creation. Thereafter, the superseded description may be stored off-site.

(2) If an owner or operator has elected to implement the requirements of paragraph (g)(1) of this section, and a period of 6 consecutive months has passed without an excursion as defined in paragraph (g)(2)(iv) of this section, the owner or operator is no longer required to record the daily average value for that parameter for that unit of equipment, for any operating day when the daily average value is less than the maximum, or greater than the minimum established limit. With approval by the Administrator, monitoring data generated prior to the compliance date of this subpart shall be credited toward the period of 6 consecutive months, if the parameter limit and the monitoring was required and/or approved by the Administrator.

(i) If the owner or operator elects not to retain the daily average values, the owner or operator shall notify the Administrator in the next periodic report. The notification shall identify the parameter and unit of equipment.

(ii) If, on any operating day after the owner or operator has ceased recording daily averages as provided in paragraph (g)(2) of this section, there is an excursion as defined in paragraph (g)(2)(iv) of this section, the owner or operator shall immediately resume retaining the daily average value for each day, and shall notify the Administrator in the next periodic report. The owner or operator shall continue to retain each daily average value until another period of 6 consecutive months has passed without an excursion as defined in paragraph (g)(2)(iv) of this section.

(iii) The owner or operator shall retain the records specified in paragraphs (g)(1) (i), (ii), (iii), (iv), (v), and (vi) of this section. For any calendar week, if compliance with paragraphs (g)(1) (i), (ii), (iii), and (iv) of this section does not result in retention of a record of at least one occurrence or measured parameter value, the owner or operator shall record and retain at least one parameter value during a period of operation other than a startup, shutdown, or malfunction. For each source as defined in § 63.101, on and after July 15, 2027, the phrase ''other than a startup, shutdown, or malfunction'' in this paragraph no longer applies.

(iv) For purposes of paragraph (g) of this section, an excursion means that the daily average value of monitoring data for a parameter is greater than the maximum, or less than the minimum established value, except as provided in paragraphs (g)(2)(iv)(A) and (B) of this section.

(A) The daily average value during any startup, shutdown, or malfunction shall not be considered an excursion for purposes of this paragraph (g)(2), if the owner or operator operates the source during such periods in accordance with § 63.102(a)(4). For each source as defined in § 63.101, on and after July 15, 2027, this paragraph no longer applies.

(B) An excused excursion, as described in § 63.152(c)(2)(ii)(B) and (C), shall not be considered an excursion for purposes of this paragraph (g)(2).

(h) Beginning no later than July 15, 2024, owners and operators must submit performance test reports in accordance with this paragraph. Unless otherwise specified in this subpart, within 60 days after the date of completing each performance test required by this subpart, owners and operators must submit the results of the performance test following the procedures specified in § 63.9(k). Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, owners and operators may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

■ 90. Amend § 63.153 by revising paragraph (c) introductory text and adding paragraph (c)(5) as follows:

§ 63.153 Implementation and enforcement.

* * * * *

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (5) of this section.

* * * * *

(5) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

■ 91. Revise table 3 to subpart G to read as follows:

TABLE 3 TO SUBPART G OF PART 63—PROCESS VENTS—MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS FOR CONTROL DEVICES AND RECAPTURE DEVICES

Control or recapture device	Parameters to be monitored [a]	Recordkeeping and reporting requirements for monitored parameters
Thermal incinerator, other than a thermal oxidizer used to comply with § 63.124.	Firebox temperature [b] [63.114(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]
Thermal oxidizer used to comply with § 63.124.	Combustion chamber temperature [63.124(b)(5)(i)].	1. Continuous records.[c] 2. Record and report the combustion chamber temperature averaged over the full period of the performance test—NCS.[d]

TABLE 3 TO SUBPART G OF PART 63—PROCESS VENTS—MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS FOR CONTROL DEVICES AND RECAPTURE DEVICES—Continued

Control or recapture device	Parameters to be monitored[a]	Recordkeeping and reporting requirements for monitored parameters
		3. Record each 1-hour block average firebox temperature for each operating day. 4. Report all 1-hour block 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]
Thermal oxidizer used to comply with §63.124 (Continued).	Flue gas flow rate [63.124(b)(5)(ii)]	1. Continuous records.[c] 2. Record and report the flue gas flow rate averaged over the full period of the performance test—NCS.[d] 3. Record each 1-hour block average flue gas flow rate for each operating day. 4. Report all 1-hour block flue gas flow rates 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 [63.114(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. 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]
Flare (if meeting the requirements of §63.11(b)).	Presence of a flame at the pilot light [§63.114(a)(2)].	1. Hourly records of whether the monitor was continuously operating and whether the 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 are absent or the monitor is not operating. 4. Report the times and durations of all periods when all pilot flames of a flare are absent—PR.[g]
Flare (if meeting the requirements of §63.108).	The parameters are specified in §63.108	1. Records as specified in §63.108(m) of subpart F of this part. 2. Report information as specified in §63.108(l) of subpart F of this part—PR.[g]
Boiler or process heater with a design heat input capacity less than 44 megawatts and vent stream is *not* introduced with or as the primary fuel.	Firebox temperature[b] [§63.114(a)(3)]	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]
Scrubber for halogenated vent streams (*Note:* Controlled by a combustion device other than a flare).	pH of scrubber effluent [§63.114(a)(4)(i)], and	1. Continuous records.[c] 2. Record and report the pH of the scrubber effluent averaged over the full period of the performance test—NCS.[d] 3. Record the daily average pH of the scrubber effluent for each operating day.[e] 4. Report all daily average pH values of the scrubber effluent 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]
Scrubber for halogenated vent streams (*Note:* Controlled by a combustion device other than a flare) (Continued).	Scrubber liquid and gas flow rates [§63.114(a)(4)(ii)].	1. Continuous records of scrubber liquid flow rate.[c] 2. Record and report the scrubber liquid/gas ratio averaged over the full period of the performance test—NCS.[d] 3. Record the daily average scrubber liquid/gas ratio for each operating day.[e] 4. Report all daily average scrubber liquid/gas ratios 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]
All control devices	Presence of flow diverted to the atmosphere from the control device [§63.114(d)(1)] *or*	1. Hourly records of whether the flow indicator was operating and whether diversion was detected at any time during each hour. 2. 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] 3. For each source as defined in §63.101, beginning no later than the compliance dates specified in §63.100(k)(10), record and report the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of organic HAP in the gas in parts per million by volume and the resulting mass emissions of organic HAP in pounds that bypass a control device. For periods when the flow indicator is not operating, report the start date, start time, and duration in hours—PR.[g]
All control devices (Continued)	Monthly inspections of sealed valves [§63.114(d)(2)].	1. Records that monthly inspections were performed. 2. Record and report all monthly inspections that show the valves are moved to the diverting position or the seal has been changed—PR.[g]

TABLE 3 TO SUBPART G OF PART 63—PROCESS VENTS—MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS FOR CONTROL DEVICES AND RECAPTURE DEVICES—Continued

Control or recapture device	Parameters to be monitored[a]	Recordkeeping and reporting requirements for monitored parameters
		3. For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), record and report the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of organic HAP in the gas in parts per million by volume and the resulting mass emissions of organic HAP in pounds that bypass a control device. For periods when the flow indicator is not operating, report the start date, start time, and duration in hours—PR.[g]
All recapture devices (as an alternative to the below for absorbers, condensers, and carbon adsorbers).	Concentration level or reading indicated by an organic monitoring device at the outlet of the recovery device [§ 63.114(a)(5)(i)].	1. Continuous records.[c] 2. Record and report the concentration level or reading averaged over the full period of the performance test—NCS.[d] 3. Record the daily average concentration level or reading for each operating day.[e] 4. Report all daily average concentration levels or readings that are outside the range established in the NCS or operating permit—PR.[g]
Absorber[h]	Exit temperature of the absorbing liquid [§ 63.114(a)(5)(ii)], and	1. Continuous records.[c] 2. Record and report the exit temperature of the absorbing liquid averaged over the full period of the performance test—NCS.[d] 3. Record the daily average exit temperature of the absorbing liquid for each operating day.[e] 4. Report all the daily average exit temperatures of the absorbing liquid that are outside the range established in the NCS or operating permit—PR.[g]
Absorber[h] (Continued)	Exit specific gravity [§ 63.114(a)(5)(ii)]	1. Continuous records.[c] 2. Record and report the exit specific gravity averaged over the full period of the performance test—NCS.[d] 3. Record the daily average exit specific gravity for each operating day.[e] 4. Report all daily average exit specific gravity values that are outside the range established in the NCS or operating permit—PR.[g]
Condenser[h]	Exit (product side) temperature [§ 63.114(a)(5)(iii)].	1. Continuous records.[c] 2. Record and report the exit temperature averaged over the full period of the performance test—NCS.[d] 3. Record the daily average exit temperature for each operating day[e]. 4. Report all daily average exit temperatures that are outside the range established in the NCS or operating permit—PR.[g]
Carbon adsorber[h]	Total regeneration stream mass or volumetric flow during carbon bed regeneration cycle(s) [§ 63.114(a)(5)(iv)], and	1. Record of total regeneration stream mass or volumetric flow for each carbon bed regeneration cycle. 2. Record and report the total regeneration stream mass or volumetric flow during each carbon bed regeneration cycle during the period of the performance test—NCS.[d] 3. Report all carbon bed regeneration cycles when the total regeneration stream mass or volumetric flow is outside the range established in the NCS or operating permit—PR.[g]
Carbon adsorber[h] (Continued)	Temperature of the carbon bed after regeneration [and within 15 minutes of completing any cooling cycle(s)] [§ 63.114(a)(5)(iv)].	1. Records of the temperature of the carbon bed after each regeneration. 2. Record and report the temperature of the carbon bed after each regeneration during the period of the performance test—NCS.[d] 3. Report all carbon bed regeneration cycles during which temperature of the carbon bed after regeneration is outside the range established in the NCS or operating permit—PR.[g]
Carbon adsorber[h] (Continued)	Outlet HAP or TOC concentration [§ 63.114(a)(5)(v)].	For each nonregenerative adsorber and regenerative adsorber that is regenerated offsite subject to the requirements in § 63.114(a)(5)(v), the owner or operator must record each outlet HAP or TOC concentration measured according to §§ 63.114(a)(5)(v)(B) and (C).
Carbon adsorber[h] (Continued)	Adsorbent replacement [§ 63.114(a)(5)(v)]	1. For each nonregenerative adsorber and regenerative adsorber that is regenerated offsite subject to the requirements in § 63.114(a)(5)(v), the owner or operator must record date and time the adsorbent was last replaced.
Carbon adsorber[h] (Continued)	Breakthrough [§ 63.114(a)(5)(v)]	For each nonregenerative adsorber and regenerative adsorber that is regenerated offsite subject to the requirements in § 63.114(a)(5)(v), the owner or operator must: 1. Record breakthrough limit and bed life established according to § 63.114(a)(5)(v)(A). 2. Report the date of each instance when breakthrough, as defined in § 63.101, is detected between the first and second adsorber and the adsorber is not replaced according to § 63.114(a)(5)(v)(A)(*1*)—PR.[g]
Scrubber with a reactant tank used to comply with § 63.124.	Liquid-to-gas ratio [§ 63.124(b)(4)(i)]	1. Continuous records.[c] 2. Record and report the L/G of the scrubber averaged over the full period of the performance test—NCS.[d] 3. Record each 1-hour block L/G of the scrubber for each operating day. 4. Report all 1-hour block L/G values of the scrubber 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]
Scrubber with a reactant tank used to comply with § 63.124 (Continued).	In lieu of liquid-to-gas ratio, scrubber total liquid flow rate and gas flow rate through scrubber [§ 63.124(b)(4)(i)].	1. Continuous records.[c] 2. Record and report both the total scrubber liquid flow rate and gas flow rate through the scrubber averaged over the full period of the performance test—NCS.[d]

TABLE 3 TO SUBPART G OF PART 63—PROCESS VENTS—MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS FOR CONTROL DEVICES AND RECAPTURE DEVICES—Continued

Control or recapture device	Parameters to be monitored [a]	Recordkeeping and reporting requirements for monitored parameters
		3. Record each 1-hour block total scrubber liquid flow rate and each 1-hour block gas flow rate through the scrubber for each operating day. 4. Report all 1-hour block total scrubber liquid flow rate values and all 1-hour block gas flow rate through the scrubber values 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]
Scrubber with a reactant tank used to comply with § 63.124 (Continued).	pH of liquid in reactant tank [§ 63.124(b)(4)(ii)].	1. Continuous records.[c] 2. Record and report the pH of liquid in reactant tank averaged over the full period of the performance test—NCS.[d] 3. Record each 1-hour block pH of liquid in reactant tank for each operating day. 4. Report all 1-hour block values of the pH of liquid in reactant tank 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]
Scrubber with a reactant tank used to comply with § 63.124 (Continued).	Pressure drop [§ 63.124(b)(4)(iii)]	1. Continuous records.[c] 2. Record and report the pressure drop of the scrubber averaged over the full period of the performance test—NCS.[d] 3. Record each 1-hour block pressure drop of the scrubber for each operating day. 4. Report all 1-hour block pressure drop values 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]
Scrubber with a reactant tank used to comply with § 63.124 (Continued).	Temperature of scrubbing liquid entering column [§ 63.124(b)(4)(iv)].	1. Continuous records.[c] 2. Record and report the temperature of scrubbing liquid entering column averaged over the full period of the performance test—NCS.[d] 3. Record each 1-hour block temperature of scrubbing liquid entering column for each operating day. 4. Report all 1-hour block values of the temperature of scrubbing liquid entering column 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]
Scrubber with a reactant tank used to comply with § 63.124 (Continued).	Liquid feed pressure [§ 63.124(b)(4)(v)]	1. Continuous records.[c] 2. Record and report the liquid feed pressure of the scrubber averaged over the full period of the performance test—NCS.[d] 3. Record each 1-hour block liquid feed pressure of the scrubber for each operating day. 4. Report all 1-hour block liquid feed pressure values 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]
Sorbent injection	Sorbent injection rate [b] [§ 63.114(a)(6)(i)]	1. Continuous records.[c] 2. Record and report the sorbent injection rate averaged over the full period of the performance test—NCS.[d] 3. Record the daily average sorbent injection rate for each operating day.[e] 4. Report all daily average sorbent injection rates 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]
Sorbent injection (Continued)	Carrier gas flow rate [b] [§ 63.114(a)(6)(ii)]	1. Continuous records.[c] 2. Record and report the carrier gas flow rate averaged over the full period of the performance test—NCS.[d] 3. Record the daily average carrier gas flow rate for each operating day.[e] 4. Report all daily average carrier gas flow rates 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]

[a] Regulatory citations are listed in brackets.

[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 § 63.111 of this subpart.

[d] NCS = Notification of Compliance Status described in § 63.152 of this subpart.

[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] The periodic reports shall include the duration of periods when monitoring data is not collected for each excursion as defined in § 63.152(c)(2)(ii)(A) of this subpart.

[g] PR = Periodic Reports described in § 63.152 of this subpart.

[h] Alternatively, these devices may comply with the organic monitoring device provisions listed at this table under "All recapture devices.".

■ 92. Revise the heading of table 4 to subpart G to read as follows:

Table 4 to Subpart G of Part 63—Process Vents—Monitoring, Recordkeeping, and Reporting Requirements for Maintaining a TRE Index Value >1.0 and. ≤4.0 [No Longer Applicable in Accordance With § 63.113(a)(4)]

* * * * *

■ 93. Revise table 5 to subpart G to read as follows:

Table 5 to Subpart G of Part 63—Group 1 Storage Vessels at Existing Sources

Vessel capacity (cubic meters)	Vapor pressure [a] (kilopascals)
75 ≤ capacity <151 [b]	[b] ≥13.1
38 ≤ capacity <151 [c]	[c] ≥6.9
151 ≤ capacity	≥5.2

[a] Maximum true vapor pressure of total organic HAP at storage temperature.

[b] For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), these vessel capacity and vapor pressure criterion no longer apply.

[c] For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), these vessel capacity and vapor pressure criterion apply.

■ 94. Revise table 6 to subpart G to read as follows:

Table 6 to Subpart G of Part 63—Group 1 Storage Vessels at New Sources

Vessel capacity (cubic meters)	Vapor pressure [a] (kilopascals)
38 ≤ capacity <151[b]	≥13.1[b]
38 ≤ capacity <151[c]	≥6.9[c]
151 ≤ capacity	≥0.7

[a] Maximum true vapor pressure of total organic HAP at storage temperature.

[b] For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), these vessel capacity and vapor pressure criterion no longer apply.

[c] For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), these vessel capacity and vapor pressure criterion apply.

■ 95. Revise table 7 to subpart G to read as follows:

Table 7 to Subpart G of Part 63—Transfer Operations—Monitoring, Recordkeeping, and Reporting Requirements for Complying With 98 Weight-Percent Reduction of Total Organic Hazardous Air Pollutants 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] [§ 63.127(a)(1)(i)]	1. Continuous records [c] during loading. 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 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 [§ 63.127(a)(1)(ii)].	1. Continuous records during loading. 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. 3. Record the daily average upstream temperature and temperature difference across 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. 5. Report all daily average temperature differences across the catalyst bed that are outside the range established in the NCS or operating permit—PR. 6. Report all operating days when insufficient monitoring data are collected.[f]
Boiler or process heater with a design heat input capacity less than 44 megawatts and vent stream is not introduced with or as the primary fuel.	Firebox temperature [b] [§ 63.127(a)(3)]	1. Continuous records during loading. 2. Record and report the firebox temperature averaged over the full period of the performance test—NCS. 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 data are collected[f]—PR.
Flare (if meeting the requirements of § 63.126(b)(2)(i)).	Presence of a flame at the pilot light [§ 63.127(a)(2)].	1. Hourly records of whether the monitor was continuously operating and whether the 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. 3. Record the times and durations of all periods when all pilot flames are absent or the monitor is not operating.

TABLE 7 TO SUBPART G OF PART 63—TRANSFER OPERATIONS—MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS FOR COMPLYING WITH 98 WEIGHT-PERCENT REDUCTION OF TOTAL ORGANIC HAZARDOUS AIR POLLUTANTS EMISSIONS OR A LIMIT OF 20 PARTS PER MILLION BY VOLUME—Continued

Control device	Parameters to be monitored [a]	Recordkeeping and reporting requirements for monitored parameters
		4. Report the duration of all periods when all pilot flames of a flare are absent—PR.
Flare (if meeting the requirements of § 63.108).	The parameters are specified in § 63.108	1. Records as specified in § 63.108(m) of subpart F of this part. 2. Report information as specified in § 63.108(l) of subpart F of this part—PR.
Scrubber for halogenated vent streams (*Note:* Controlled by a combustion device other than a flare).	pH of scrubber effluent [§ 63.127(a)(4)(i)], and.	1. Continuous records during loading. 2. Record and report the pH of the scrubber effluent averaged over the full period of the performance test—NCS. 3. Record the daily average pH of the scrubber effluent for each operating day.[e] 4. Report all daily average pH values of the scrubber effluent that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected[f]—PR.
	Scrubber liquid and gas flow rates [§ 63.127(a)(4)(ii)].	1. Continuous records during loading of scrubber liquid flow rate. 2. Record and report the scrubber liquid/gas ratio averaged over the full period of the performance test—NCS. 3. Record the daily average scrubber liquid/gas ratio for each operating day.[e] 4. Report all daily average scrubber liquid/gas ratios that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected[f]—PR.
Absorber[h]	Exit temperature of the absorbing liquid [§ 63.127(b)(1)], and	1. Continuous records during loading. 2. Record and report the exit temperature of the absorbing liquid averaged over the full period of the performance test—NCS. 3. Record the daily average exit temperature of the absorbing liquid for each operating day.[e] 4. Report all daily average exit temperatures of the absorbing liquid that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected[f]—PR.
	Exit specific gravity [§ 63.127(b)(1)]	1. Continuous records during loading. 2. Record and report the exit specific gravity averaged over the full period of the performance test—NCS. 3. Record the daily average exit specific gravity for each operating day.[e] 4. Report all daily average exit specific gravity values that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected[f]—PR.
Condenser[h]	Exit (product side) temperature [§ 63.127(b)(2)].	1. Continuous records during loading. 2. Record and report the exit temperature averaged over the full period of the performance test—NCS. 3. Record the daily average exit temperature for each operating day.[e] 4. Report all daily average exit 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.
Carbon adsorber[h]	Total regeneration stream mass or volumetric or volumetric flow during carbon bed regeneration cycle(s) [§ 63.127(b)(3)], and	1. Record of total regeneration stream mass or volumetric flow for each carbon bed regeneration cycle. 2. Record and report the total regeneration stream mass or volumetric flow during each carbon bed regeneration cycle during the period of the performance test—NCS. 3. Report all carbon bed regeneration cycles when the total regeneration stream mass or volumetric flow is outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected[f]—PR.
	Temperature of the carbon bed after regeneration [and within 15 minutes of completing any cooling cycle(s)] [§ 63.127(b)(3)].	1. Records of the temperature of the carbon bed after each regeneration. 2. Record and report the temperature of the carbon bed after each regeneration during the period of the performance test—NCS. 3. Report all the carbon bed regeneration cycles during which the temperature of the carbon bed after regeneration is outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected[f]—PR.
	Outlet HAP or TOC concentration [§ 63.127(b)(4)].	For each nonregenerative adsorber and regenerative adsorber that is regenerated offsite subject to the requirements in § 63.127(b)(4), the owner or operator must record each outlet HAP or TOC concentration measured according to §§ 63.127(b)(4)(ii) and (iii).
	Adsorbent replacement [§ 63.127(b)(4)]	1. For each nonregenerative adsorber and regenerative adsorber that is regenerated offsite subject to the requirements in § 63.127(b)(4), the owner or operator must record date and time the adsorbent was last replaced.
	Breakthrough [§ 63.127(b)(4)]	For each nonregenerative adsorber and regenerative adsorber that is regenerated offsite subject to the requirements in § 63.127(b)(4), the owner or operator must: 1. Record breakthrough limit and bed life established according to § 63.127(b)(4)(i). 2. Report the date of each instance when breakthrough, as defined in § 63.101, is detected between the first and second adsorber and the adsorber is not replaced according to § 63.127(b)(4)(iii)(A)—PR.

TABLE 7 TO SUBPART G OF PART 63—TRANSFER OPERATIONS—MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS FOR COMPLYING WITH 98 WEIGHT-PERCENT REDUCTION OF TOTAL ORGANIC HAZARDOUS AIR POLLUTANTS EMISSIONS OR A LIMIT OF 20 PARTS PER MILLION BY VOLUME—Continued

Control device	Parameters to be monitored [a]	Recordkeeping and reporting requirements for monitored parameters
All recovery devices (as an alternative to the above).	Concentration level or reading indicated by an organic monitoring device at the outlet of the recovery device [§ 63.127(b)].	1. Continuous records during loading. 2. Record and report the concentration level or reading averaged over the full period of the performance test—NCS. 3. Record the daily average concentration level or reading for each operating day.[d] 4. Report all daily average concentration levels or readings that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected[f]—PR.
All control devices and vapor balancing systems.	Presence of flow diverted to the atmosphere from the control device [§ 63.127(d)(1)] or	1. Hourly records of whether the flow indicator was operating and whether a diversion was detected at any time during each hour. 2. Record and report the duration of all periods when the vent stream is diverted through a bypass line or the monitor is not operating—PR. 3. For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), record and report the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of organic HAP in the gas in parts per million by volume and the resulting mass emissions of organic HAP in pounds that bypass a control device. For periods when the flow indicator is not operating, report the start date, start time, and duration in hours—PR.
	Monthly inspections of sealed valves [§ 63.127(d)(2)].	1. Records that monthly inspections were performed. 2. Record and report all monthly inspections that show the valves are moved to the diverting position or the seal has been changed. 3. For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), record and report the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of organic HAP in the gas in parts per million by volume and the resulting mass emissions of organic HAP in pounds that bypass a control device. For periods when the flow indicator is not operating, report the start date, start time, and duration in hours—PR.

[a] Regulatory citations are listed in brackets.

[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 § 63.111 of this subpart.

[d] NCS = Notification of Compliance Status described in § 63.152 of this subpart.

[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] The periodic reports shall include the duration of periods when monitoring data are not collected for each excursion as defined in § 63.152(c)(2)(ii)(A) of this subpart.

[g] PR = Periodic Reports described in § 63.152 of this subpart.

[h] Alternatively, these devices may comply with the organic monitoring device provisions listed at the end of this table under "All Recovery Devices."

■ 96. Amend table 8 to subpart G by adding the entry for "Ethylene oxide" in alphabetical order to read as follows:

TABLE 8 TO SUBPART G OF PART 63—ORGANIC HAP'S SUBJECT TO THE WASTEWATER PROVISIONS FOR PROCESS UNITS AT NEW SOURCES

Chemical name	CAS No. [a]
* * * * *	
Ethylene oxide	75218
* * * * *	

■ 97. Revise table 13 to subpart G to read as follows:

TABLE 13 TO SUBPART G OF PART 63—WASTEWATER—MONITORING REQUIREMENTS FOR CONTROL DEVICES

Control device	Monitoring equipment required	Parameters to be monitored	Frequency
All control devices	1. Flow indicator installed at all bypass lines to the atmosphere and equipped with continuous recorder [b] *or*	1. Presence of flow diverted from the control device to the atmosphere *or*	Hourly records of whether the flow indicator was operating and whether a diversion was detected at any time during each hour.
	2. Valves sealed closed with car-seal or lock-and-key configuration.	2. Monthly inspections of sealed valves	Monthly.
Thermal Incinerator	Temperature monitoring device installed in firebox or in ductwork immediately downstream of firebox [a] and equipped with a continuous recorder [b].	Firebox temperature	Continuous.

TABLE 13 TO SUBPART G OF PART 63—WASTEWATER—MONITORING REQUIREMENTS FOR CONTROL DEVICES—Continued

Control device	Monitoring equipment required	Parameters to be monitored	Frequency
Catalytic Incinerator	Temperature monitoring device installed in gas stream immediately before and after catalyst bed and equipped with a continuous recorder [b].	1. Temperature upstream of catalyst bed *or* 2. Temperature difference across catalyst bed.	Continuous.
Flare (if meeting the requirements of § 63.139(c)(3)).	Heat sensing device installed at the pilot light and equipped with a continuous recorder [a].	Presence of a flame at the pilot light	Hourly records of whether the monitor was continuously operating and whether the pilot flame was continuously present during each hour.
Flare (if meeting the requirements of § 63.108).	The monitoring equipment is specified in § 63.108.	The parameters are specified in § 63.108.	The frequency is specified in § 63.108.
Boiler or process heater <44 megawatts and vent stream is not mixed with the primary fuel.	Temperature monitoring device installed in firebox [a] and equipped with continuous recorder [b].	Combustion temperature	Continuous.
Condenser	Temperature monitoring device installed at condenser exit and equipped with continuous recorder [b].	Condenser exit (product side) temperature.	Continuous.
Carbon adsorber (regenerative, regenerated onsite).	Integrating regeneration stream flow monitoring device having an accuracy of ±10 percent, *and*	Total regeneration stream mass or volumetric flow during carbon bed regeneration cycle(s).	For each regeneration cycle, record the total regeneration stream mass or volumetric flow.
	Carbon bed temperature monitoring device.	Temperature of carbon bed after regeneration [and within 15 minutes of completing any cooling cycle(s)].	For each regeneration cycle and within 15 minutes of completing any cooling cycle, record the carbon bed temperature.
Carbon adsorber (Non-regenerative or regenerative, regenerated offsite).	Organic compound concentration monitoring device[c].	Organic compound concentration of adsorber exhaust.	Daily or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater.
	The monitoring equipment is specified in § 63.139(d)(5).	The parameters are specified in § 63.139(d)(5).	The frequency is specified in § 63.139(d)(5).
Organic monitoring device [d]	Organic monitoring device installed at the outlet of the control device.	Organic compound concentration of control device exhaust.	Continuous.
Alternative monitoring parameters	Other parameters may be monitored upon approval from the Administrator in accordance with the requirements in § 63.143(e)(3).		

[a] Monitor may be installed in the firebox or in the ductwork immediately downstream of the firebox before any substantial heat exchange is encountered.

[b] "Continuous recorder" is defined in § 63.111 of this subpart.

[c] 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. For each source as defined in § 63.101, on and after July 15, 2027, this footnote no longer applies.

[d] A continuous organic monitoring device may be used in lieu of the requirements outlined for thermal incinerators, catalytic incinerators, boilers, process heaters, condensers, and carbon adsorbers.

■ 98. Revise table 20 to subpart G to read as follows:

TABLE 20 TO SUBPART G OF PART 63—WASTEWATER—PERIODIC REPORTING REQUIREMENTS FOR CONTROL DEVICES SUBJECT TO § 63.139 USED TO COMPLY WITH §§ 63.13 THROUGH 63.139

Control device	Reporting requirements
(1) Thermal Incinerator. Report all daily average [a] temperatures that are outside the range established in the NCS [b] or operating permit and all operating days when insufficient monitoring data are collected.[c]	
(2) Catalytic Incinerator	(i) Report all daily average [a] upstream temperatures that are outside the range established in the NCS [b] or operating permit. (ii) Report all daily average [a] temperature differences across the catalyst bed that are outside the range established in the NCS [b] or operating permit. (iii) Report all operating days when insufficient monitoring data are collected.[c]
(3) Boiler or Process Heater with a design heat input capacity less than 44 megawatts and vent stream is not mixed with the primary fuel.	Report all daily average [a] firebox temperatures that are outside the range established in the NCS [b] or operating permit and all operating days when insufficient monitoring data are collected.[c]
(4a) Flare (if meeting the requirements of § 63.139(c)(3))	Report the duration of all periods when all pilot flames are absent.
(4b) Flare (if meeting the requirements of § 63.108)	The reporting requirements are specified in § 63.108(l) of subpart F of this part.
(5) Condenser	Report all daily average [a] exit temperatures that are outside the range established in the NCS [b] or operating permit and all operating days when insufficient monitoring data are collected.[c]
(6) Carbon Adsorber (Regenerative)	(i) Report all carbon bed regeneration cycles when the total regeneration stream mass or volumetric flow is outside the range established in the NCS [b] or operating permit. (ii) Report all carbon bed regeneration cycles during which the temperature of the carbon bed after regeneration is outside the range established in the NCS [b] or operating permit.

TABLE 20 TO SUBPART G OF PART 63—WASTEWATER—PERIODIC REPORTING REQUIREMENTS FOR CONTROL DEVICES SUBJECT TO § 63.139 USED TO COMPLY WITH §§ 63.13 THROUGH 63.139—Continued

Control device	Reporting requirements
	(iii) Report all operating days when insufficient monitoring data are collected[c]. (iv) For each regenerative adsorber that is regenerated offsite subject to the requirements in § 63.139(d)(5) report the date of each instance when breakthrough, as defined in § 63.101, is detected between the first and second adsorber and the adsorber is not replaced according to § 63.139(d)(5)(iii)(A).
(7) Carbon Adsorber (Non-Regenerative)	(i) Report all operating days when inspections not done according to the schedule developed as specified in table 13 of this subpart. (ii) Report all operating days when carbon has not been replaced at the frequency specified in table 13 of this subpart. (iii) For each nonregenerative adsorber subject to the requirements in § 63.139(d)(5), report the date of each instance when breakthrough, as defined in § 63.101, is detected between the first and second adsorber and the adsorber is not replaced according to § 63.139(d)(5)(iii)(A).
(8) All Control Devices	(i) Report the times and durations of all periods when the vent stream is diverted through a bypass line or the monitor is not operating, or (ii) Report all monthly inspections that show the valves are moved to the diverting position or the seal has been changed. (iii) For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10), report the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of organic HAP in the gas in parts per million by volume and the resulting mass emissions of organic HAP in pounds that bypass a control device. For periods when the flow indicator is not operating, report the start date, start time, and duration in hours.
(9) Thermal Incinerator, Catalytic Incinerator, Boiler, Process Heater, Condenser, or Carbon Adsorber using a continuous organic monitoring device as specified in § 63.143(e)(2).	(i) Report all daily average [a] concentration levels or readings that are outside the range established in the NCS or operating permit.[c] (ii) Report all operating days when insufficient monitoring data are collected.[c]

[a] The daily average is the average of all values recorded during the operating day, as specified in § 63.147(d).

[b] NCS = Notification of Compliance Status described in § 63.152.

[c] The periodic reports shall include the duration of periods when monitoring data are not collected for each excursion as defined in § 63.152(c)(2)(ii)(A).

■ 99. Add table 38 to subpart G to read as follows:

TABLE 38 TO SUBPART G OF PART 63—TOXIC EQUIVALENCY FACTORS

Dioxin and furan congener	Toxic equivalency factor
1,2,3,7,8-pentachlorodibenzo-p-dioxin	1
1,2,3,4,7,8-hexachlorodibenzo-p-dioxin	0.1
1,2,3,7,8,9-hexachlorodibenzo-p-dioxin	0.1
1,2,3,6,7,8-hexachlorodibenzo-p-dioxin	0.1
1,2,3,4,6,7,8-heptachlorodibenzo-p-dioxin	0.01
octachlorodibenzo-p-dioxin	0.0003
2,3,7,8-tetrachlorodibenzofuran	0.1
2,3,4,7,8-pentachlorodibenzofuran	0.3
1,2,3,7,8-pentachlorodibenzofuran	0.03
1,2,3,4,7,8-hexachlorodibenzofuran	0.1
1,2,3,6,7,8-hexachlorodibenzofuran	0.1
1,2,3,7,8,9-hexachlorodibenzofuran	0.1
2,3,4,6,7,8-hexachlorodibenzofuran	0.1
1,2,3,4,6,7,8-heptachlorodibenzofuran	0.01
1,2,3,4,7,8,9-heptachlorodibenzofuran	0.01
Octachlorodibenzofuran	0.0003

■ 100. Revise the heading to subpart H to read as follows:

Subpart H—National Emission Standards for Hazardous Air Pollutants for Equipment Leaks and Fenceline Monitoring for All Emission Sources

■ 101. Amend § 63.160 by:

■ a. Revising paragraph (b)(1);

■ b. Revising and republishing paragraph (c); and

■ c. Revising paragraphs (g) introductory text and (g)(1).

The revisions and republication read as follows:

§ 63.160 Applicability and designation of source.

* * * * *

(b) * * *

(1) Part 60 of this chapter will be required to comply only with the provisions of this subpart, except as specified in §§ 60.480a(e)(2)(i) and 60.480b(e)(2)(i) of this chapter.

* * * * *

(c) If a process unit subject to the provisions of this subpart has equipment to which this subpart does not apply, but which is subject to a standard identified in paragraph (c)(1), (2), or (3) of this section, the owner or operator may elect to apply this subpart to all such equipment in the process unit. If the owner or operator elects this method of compliance, all VOC in such equipment shall be considered, for purposes of applicability and compliance with this subpart, as if it were organic hazardous air pollutant (HAP). Compliance with the provisions of this subpart, in the manner described in this paragraph, shall be deemed to constitute compliance with the standard identified in paragraph (c)(1), (2), or (3) of this section.

(1) Part 60, subpart VV, VVa, VVb, GGG, or KKK, of this chapter, except as specified in §§ 60.480a(e)(2)(i) and 60.480b(e)(2)(i) of this chapter;

(2) Part 61, subpart F or J of this chapter; or

(3) Part 264, subpart BB of this chapter or part 265, subpart BB of this chapter.

* * * * *

(g) *Alternative means of compliance*—For each source as defined in § 63.101, and for each source as defined in § 63.191, on and after July 15, 2027, this paragraph no longer applies.

(1) *Option to comply with 40 CFR part 65.* Owners or operators of CMPU that are subject to § 63.100 may choose to comply with the provisions of 40 CFR part 65 for all Group 1 and Group 2 process vents, Group 1 storage vessels, Group 1 transfer operations, and equipment that are subject to § 63.100, that are part of the CMPU. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

* * * * *

■ 102. Revise § 63.161 to read as follows:

§ 63.161 Definitions.

All terms used in this subpart shall have the meaning given them in the Act and in subpart F of this part, except as provided in any subpart that references this subpart.

■ 103. Amend § 63.163 by:

■ a. Adding paragraph (a)(1)(iii);

■ b. Revising paragraph (b)(2) introductory text and adding paragraph (b)(2)(iv);

■ c. Revising paragraph (c)(3) and adding paragraph (c)(4);

■ d. Revising paragraph (e) introductory text and adding paragraph (e)(7); and

■ e. Revising paragraphs (g), (j) introductory text and (j)(1).

The revisions and additions read as follows:

§ 63.163 Standards: Pumps in light liquid service.

(a) * * *

(1) * * *

(iii) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(11), for each pump in ethylene oxide service, as defined in § 63.101, that is added to a CMPU, and for each pump in ethylene oxide service, that replaces a pump in ethylene oxide service, owners and operators must initially monitor for leaks within 5 days after initial startup of the equipment.

* * * * *

(b) * * *

(2) Except as specified in paragraph (b)(2)(iv) of this section, the instrument reading, as determined by the method as specified in § 63.180(b), that defines a leak in each phase of the standard is:

* * * * *

(iv) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(11), for pumps in ethylene oxide service, as defined in § 63.101, the instrument reading that defines a leak for pumps is 500 parts per million or greater.

* * * * *

(c) * * *

(3) Except as specified in paragraph (c)(4) of this section, for pumps in Phase III to which a 1,000 parts per million leak definition applies, repair is not required unless an instrument reading of 2,000 parts per million or greater is detected.

(4) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(11), for pumps in ethylene oxide service, as defined in § 63.101, paragraph (c)(3) of this section is not applicable.

* * * * *

(e) Except as specified in paragraph (e)(7) of this section, each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraphs (a) through (d) of this section, provided the following requirements are met:

* * * * *

(7) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(11), for pumps in ethylene oxide service, as defined in § 63.101, paragraph (e) of this section is not applicable.

* * * * *

(g) Any pump that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage from the pump to a control device meeting the requirements of § 63.172 is exempt from the requirements of paragraphs (a)(1)(iii), and (b) through (e) of this section.

* * * * *

(j) Any pump that is designated, as described in § 63.181(b)(7)(i), as an unsafe-to-monitor pump is exempt from the requirements of paragraphs (a)(1)(iii), and (b) through (e) of this section if:

(1) The owner or operator of the pump determines that the pump is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a)(1)(iii), and (b) through (d) of this section; and

* * * * *

■ 104. Amend § 63.164 by revising paragraph (h) to read as follows:

§ 63.164 Standards: Compressors.

* * * * *

(h) A compressor is exempt from the requirements of paragraphs (a) through (g) of this section if it is equipped with a system to capture and transport leakage from the compressor drive shaft seal to a process or a fuel gas system or to a closed vent system that captures and transports leakage from the compressor to a control device meeting the requirements of § 63.172 of this subpart.

* * * * *

■ 105. Revise and republish § 63.165 to read as follows:

§ 63.165 Standards: Pressure relief devices in gas/vapor service or light liquid service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with an instrument reading of less than 500 parts per million above background except as provided in paragraph (b) of this section, as measured by the method specified in § 63.180(c). For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(10), this paragraph (a) no longer applies and instead the owner or operator must comply with paragraph (e) of this section.

(b) Except as specified in paragraph (e) of this section, comply with paragraphs (b)(1) and (b)(2) of this section.

(1) After each pressure release, the pressure relief device shall be returned to a condition indicated by an instrument reading of less than 500 parts per million above background, as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in § 63.171.

(2) No later than 5 calendar days after the pressure release and being returned to organic HAP service, the pressure relief device shall be monitored to confirm the condition indicated by an instrument reading of less than 500 parts per million above background, as measured by the method specified in § 63.180(c).

(c) Except as specified in paragraph (e) of this section, any pressure relief device that is routed to a process or fuel gas system or equipped with a closed-vent system capable of capturing and transporting leakage from the pressure relief device to a control device as described in § 63.172 is exempt from the requirements of paragraphs (a) and (b) of this section.

(d) Except as specified in paragraph (e) of this section, comply with paragraphs (d)(1) and (d)(2) of this section.

(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in § 63.171.

(e) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(10), except as specified in paragraph (e)(4) of this section, owners and operators must comply with the requirements specified in paragraphs (e)(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 paragraph (a) through (d) of this section. Except as specified in paragraphs (e)(4) and (5) of this section, owners and operators must also comply with the requirements specified in paragraphs (e)(3), (6), (7), and (8) of this section for all pressure relief devices in organic HAP service.

(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 measured by the method in § 63.180(c).

(2) *Pressure release requirements.* For pressure relief devices in organic HAP gas or vapor service, owners and operators must comply with the applicable requirements paragraphs (e)(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 § 63.180(c), 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 (e)(2)(i) of this section (and do not replace 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.

(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. Owners and operators must not initiate startup of the equipment served by the rupture disk until the rupture disc is replaced.

(3) *Pressure release management.* Except as specified in paragraphs (e)(4) and (5) of this section, owners and operators must comply with the requirements specified in paragraphs (e)(3)(i) through (v) of this section for all pressure relief devices in organic HAP service.

(i) Owners and operators 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 must be either specific to the pressure relief device itself or must 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) Owners and operators 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, liquid level and pressure indicators with deadman switches, monitors, or automatic actuators. Independent, non-duplicative systems within this category count as separate redundant prevention measures.

(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 the initial pressure relief device (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, owners and operators must perform root cause analysis and corrective action analysis according to the requirement in paragraph (e)(6) of this section and implement corrective actions according to the requirements in paragraph (e)(7) of this section. Owners and operators must also calculate the quantity of organic HAP released during each pressure release event and report this quantity as required in § 63.182(d)(2)(xviii). 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) Owners and operators must determine the total number of release events that occurred during the calendar year for each affected pressure relief device separately.

(v) Except for pressure relief devices described in paragraphs (e)(4) and (5) of this section, the following release events from an affected pressure relief device are a violation of the pressure release management work practice standards.

(A) Except as specified in paragraph (e)(3)(v)(D) of this section, any release event for which the root cause of the event was determined to be operator error or poor maintenance.

(B) Except as specified in paragraph (e)(3)(v)(D) of this section, a second release event from a single pressure relief device in a 3 calendar year period for the same root cause for the same equipment.

(C) Except as specified in paragraph (e)(3)(v)(D) of this section, a third release event from a single pressure relief device in a 3 calendar year period for any reason.

(D) Paragraphs (e)(3)(v)(A) through (e)(3)(v)(C) of this section do not apply to pressure relief devices in ethylene oxide service, as defined in § 63.101; instead, any release event from an affected pressure relief device in ethylene oxide service is a violation of the pressure release management work practice standards.

(4) *Pressure relief devices routed to a control device, process, fuel gas system, or drain system.* (i) 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, to the fuel gas system, or to a drain system, then owners and operators are not required to comply with paragraph (e)(1), (2), or (3) of this section.

(ii) Both the closed vent system and control device (if applicable) referenced in paragraph (e)(4)(i) of this section must meet the applicable requirements specified in § 63.172.

(iii) The drain system (if applicable) referenced in paragraph (e)(4)(i) of this section must meet the applicable requirements specified in § 63.136(e).

(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 (e)(3) of this section.

(i) Pressure relief devices in heavy liquid service, as defined in § 63.161.

(ii) Thermal expansion relief valves.

(iii) Pressure relief devices on mobile equipment.

(iv) Pilot-operated pressure relief devices where the primary release valve is routed through a closed vent system to a control device or back into the process, to the fuel gas system, or to a drain system.

(v) Balanced bellows pressure relief devices where the primary release valve is routed through a closed vent system to a control device or back into the process, to the fuel gas system, or to a drain system.

(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 (e)(6)(i) through (iii) of this section.

(i) Owners and operators 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) [Reserved]

(iii) Except as provided in paragraph (e)(6)(i) of this section, if more than one pressure relief device has a release during the same time period, an initial root cause analysis must 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.* Owners and operators must conduct a root cause analysis and corrective action analysis as specified in paragraphs (e)(3)(iii) and (e)(6) of this section, and owners and operators must implement the corrective action(s) identified in the corrective action analysis in accordance with the applicable requirements in paragraphs (e)(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 the owner or operator concludes that no corrective action should be implemented, the owner or operator must 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, owners and operators must 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, owners and operators must 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.

(8) *Flowing pilot-operated pressure relief devices.* For affected sources that commenced construction or reconstruction on or before April 25, 2023, owners and operators are prohibited from installing a flowing pilot-operated pressure relief device or replacing any pressure relief device with a flowing pilot-operated pressure relief device after July 15, 2027. For affected sources that commenced construction or reconstruction after April 25, 2023, owners and operators are prohibited from installing and operating flowing pilot-operated pressure relief devices. For purpose of compliance with this paragraph, a flowing pilot-operated pressure relief device means the type of pilot-operated pressure relief device where the pilot discharge vent continuously releases emissions to the atmosphere when the pressure relief device is actuated.

■ 106. Amend § 63.168 by:

■ a. Revising paragraph (b)(2) introductory text and adding paragraph (b)(2)(iv); and

■ b. Revising paragraph (d) introductory text and and adding paragraph (d)(5).

The revisions and additions read as follows:

§ 63.168 Standards: Valves in gas/vapor service and in light liquid service.

* * * * *

(b) * * *

(2) Except as specified in paragraph (b)(2)(iv) of this section, the instrument reading that defines a leak in each phase of the standard is:

* * * * *

(iv) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(11), for valves in ethylene oxide service, as defined in § 63.101, that are either in gas service or in light liquid service the instrument reading that defines a leak is 100 parts per million or greater.

* * * * *

(d) Except as specified in paragraph (d)(5) of this section, in Phase III, the owner or

* * * * *

(5) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(11), for valves in ethylene oxide service, as defined in § 63.101, that are either in gas service or in light

liquid service the monitoring period is once per month.

* * * * *

■ 107. Revise § 63.170 to read as follows:

§ 63.170 Standards: Surge control vessels and bottoms receivers.

(a) Except as specified in paragraph (b) of this section, each surge control vessel or bottoms receiver that is not routed back to the process and that meets the conditions specified in table 2 or table 3 of this subpart shall be equipped with a closed-vent system that routes the organic vapors vented from the surge control vessel or bottoms receiver back to the process or to a control device that complies with the requirements in § 63.172, except as provided in § 63.162(b), or comply with the requirements of § 63.119(b) or (c).

(b) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(10), paragraph (a) of this section no longer applies. Instead, each surge control vessel and bottoms receiver that is not routed back to the process and emits greater than or equal to 1.0 lb/hr of total organic HAP must be equipped with a closed-vent system that routes the organic vapors vented from the surge control vessel or bottoms receiver back to the process or to a control device that complies with the requirements in § 63.172, except as provided in § 63.162(b), or comply with the requirements of § 63.113(a)(1) or (a)(2).

■ 108. Amend § 63.171 by revising paragraphs (a), (c) introductory text, (d) introductory text and (e), and adding paragraph (f) to read as follows:

§ 63.171 Standards: Delay of repair.

(a) Except as specified in paragraph (f) of this section, delay of repair of equipment for which leaks have been detected is allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur by the end of the next process unit shutdown.

* * * * *

(c) Except as specified in paragraph (f) of this section, delay of repair for valves, connectors, and agitators is also allowed if:

* * * * *

(d) Except as specified in paragraph (f) of this section, delay of repair for pumps is also allowed if:

* * * * *

(e) Except as specified in paragraph (f) of this section, delay of repair beyond a process unit shutdown will be allowed for a valve if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the second process unit shutdown will not be allowed unless the third process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(11), delay of repair is not allowed for light liquid pumps in ethylene oxide service, gas/vapor and light liquid valves in ethylene oxide service, and connectors in ethylene oxide service.

■ 109. Amend § 63.172 by revising paragraphs (b), (d), (j) introductory text and (j)(3), and adding paragraph (j)(4) to read as follows:

§ 63.172 Standards: Closed-vent systems and control devices.

* * * * *

(b) Recovery or recapture devices (*e.g.,* condensers and absorbers) shall be designed and operated to recover the organic hazardous air pollutant emissions or volatile organic compounds emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, whichever is less stringent. The 20 parts per million by volume performance standard is not applicable to the provisions of § 63.179.

* * * * *

(d) Except as specified in paragraph (a) of § 63.108, flares used to comply with this subpart shall comply with the requirements of § 63.11(b).

* * * * *

(j) For each closed-vent system that contains bypass lines that could divert a vent stream away from the control device and to the atmosphere, the owner or operator shall comply with the provisions of either paragraphs (j)(1) or (j)(2), and (j)(4) of this section, except as provided in paragraph (j)(3) of this section.

* * * * *

(3) Except as specified in paragraph (j)(4) of this section, equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and pressure relief valves needed for safety purposes are not subject to this paragraph.

(4) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(10):

(i) The use of a bypass line at any time on a closed vent system (used to comply with the provisions of this subpart) to divert emissions to the atmosphere or to a control device not meeting the requirements specified in this subpart is an emissions standards violation.

(ii) Paragraph (j)(3) of this section does not apply. Instead, the exemptions specified in paragraph (j)(4)(ii)(A) and (j)(4)(ii)(B) of this section apply.

(A) Except for pressure relief devices subject to § 63.165(e)(4), equipment such as low leg drains and equipment subject to the requirements specified in subpart H of this part are not subject to this paragraph (j) of this section.

(B) Open-ended valves or lines that use a cap, blind flange, plug, or second valve and follow the requirements specified in 40 CFR 60.482–6(a)(2), (b), and (c) or follow requirements codified in another regulation that are the same as 40 CFR 60.482–6(a)(2), (b), and (c) are not subject to this paragraph (j) of this section.

* * * * *

■ 110. Amend § 63.173 by revising paragraph (f) as follows:

§ 63.173 Standards: Agitators in gas/vapor service and in light liquid service.

* * * * *

(f) Any agitator if it is equipped with a system to capture and transport leakage from the agitator to a process or a fuel gas system or to a closed vent system that captures and transports leakage from the agitator to a control device meeting the requirements of § 63.172 is exempt from the requirements of paragraphs (a) through (c) of the section.

* * * * *

■ 111. Amend § 63.174 by:

■ a. Revising paragraph (a)(2) and adding (a)(3);

■ b. Revising paragraphs (b) introductory text, (b)(3) introductory text, and adding paragraphs (b)(3)(vi) and (b)(5); and

■ c. Revising paragraphs (g) introductory text and (g)(3).

The revisions and additions read as follows:

§ 63.174 Standards: Connectors in gas/vapor service and in light liquid service.

(a) * * *

(2) Except as specified in paragraph (a)(3) of this section, if an instrument reading greater than or equal to 500 parts per million is measured, a leak is detected.

(3) For each source as defined in § 63.101, and for each source as defined

in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(11), for connectors in ethylene oxide service, as defined in § 63.101, the instrument reading that defines a leak for connectors is 100 parts per million or greater.

(b) The owner or operator shall monitor for leaks at the intervals specified in either paragraph (b)(1) or (b)(2) of this section and in paragraphs (b)(3) through (b)(5) of this section.

* * * * *

(3) After conducting the initial survey required in paragraph (b)(1) or (b)(2) of this section, the owner or operator shall perform all subsequent monitoring of connectors at the frequencies specified in paragraphs (b)(3)(i) through (b)(3)(v) of this section, except as provided in paragraphs (b)(3)(vi) and (c)(2) of this section:

* * * * *

(vi) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(11), for connectors in ethylene oxide service, as defined in § 63.101, the monitoring period is once every month and paragraph (c)(2) of this section is not applicable.

* * * * *

(5) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(11), for each connector in ethylene oxide service, as defined in § 63.101, that is added to a CMPU, and for each connector in ethylene oxide service that replaces a connector in ethylene oxide service, owners and operators must initially monitor for leaks within 5 days after initial startup of the equipment.

* * * * *

(g) Except as specified in paragraph (g)(3) of this section, any connector that is designated, as described in § 63.181(b)(7)(iii), as an unsafe-to-repair connector is exempt from the requirements of paragraphs (a), (d), and (e) of this section if:

* * * * *

(3) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(11), for connectors in ethylene oxide service, as defined in § 63.101, paragraph (g) of this section is no longer applicable.

* * * * *

■ 112. Amend § 63.180 by revising paragraphs (c) introductory text, (d)(1) and (e) introductory text to read as follows:

§ 63.180 Test methods and procedures.

* * * * *

(c) When equipment is monitored for compliance as required in §§ 63.164(i), 63.165(a) or (e)(1), and 63.172(f) or when equipment subject to a leak definition of 500 ppm is monitored for leaks as required by this subpart, the owner or operator may elect to adjust or not to adjust the instrument readings for background. If an owner or operator elects to not adjust instrument readings for background, the owner or operator shall monitor the equipment according to the procedures specified in paragraphs (b)(1) through (4) of this section. In such case, all instrument readings shall be compared directly to the applicable leak definition to determine whether there is a leak. If an owner or operator elects to adjust instrument readings for background, the owner or operator shall monitor the equipment according to the procedures specified in paragraphs (c)(1) through (c)(4) of this section.

* * * * *

(d)(1) Each piece of equipment within a process unit that can reasonably be expected to contain equipment in organic HAP service is presumed to be in organic HAP service unless an owner or operator demonstrates that the piece of equipment is not in organic HAP service. For a piece of equipment to be considered not in organic HAP service, it must be determined that the percent organic HAP content can be reasonably expected not to exceed 5 percent by weight on an annual average basis. For purposes of determining the percent organic HAP content of the process fluid that is contained in or contacts equipment, Method 18 of 40 CFR part 60, appendix A shall be used. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method.

* * * * *

(e) When a flare is used to comply with § 63.172(d), the owner or operator shall comply with paragraphs (e)(1) through (3) of this section, except as specified in paragraph (a) of § 63.108. The owner or operator is not required to conduct a performance test to determine percent emission reduction or outlet organic HAP or TOC concentration.

* * * * *

■ 113. Amend § 63.181 by:

■ a. Revising paragraphs (b)(2)(i) and (b)(3), and adding paragraphs (b)(11) and (12);

■ b. Revising paragraphs (d)(5)(i), (g)(1)(iii), (g)(2)(i) and (g)(3) introductory text; and

■ c. Adding paragraphs (g)(3)(iii) and (l).

The revisions and additions read as follows:

§ 63.181 Recordkeeping requirements.

* * * * *

(b) * * *

(2)(i) A list of identification numbers for equipment that the owner or operator elects to equip with a closed-vent system and control device, under the provisions of § 63.163(g), § 63.164(h), § 63.165(c) or (e)(4), or § 63.173(f), as applicable.

* * * * *

(3)(i) A list of identification numbers for pressure relief devices subject to the provisions in § 63.165(a) or (e)(1), as applicable.

(ii) A list of identification numbers for pressure relief devices equipped with rupture disks, under the provisions of § 63.165(d), (e)(2)(ii), or (e)(2)(iii), as applicable.

* * * * *

(11) For each pressure relief device subject to the pressure release management work practice standards in § 63.165(e), owners and operators must keep the records specified in paragraphs (b)(11)(i) through (iii) of this section in addition to the records specified in paragraph (f) of this section.

(i) Records of the prevention measures implemented as required in § 63.165(e)(3)(ii).

(ii) Records of the number of releases during each calendar year. Keep these records for the current calendar year and the past 5 calendar years.

(iii) For each release to the atmosphere, owners and operators must keep the records specified in paragraphs (b)(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 § 63.165(e)(3)(iii), including an identification of the affected facility, 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 § 63.165(e)(7)(i).

(D) For any corrective action analysis for which implementation of corrective actions are required in § 63.165(e)(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 equipment in ethylene oxide service, as defined in § 63.101, records of the percent ethylene oxide content of the process fluid and the method used to determine it.

* * * * *

(d) * * *

(5) * * *

(i) The owner or operator may develop a written procedure that identifies the conditions that justify a delay of repair. The written procedures may be included as part of the startup/shutdown/malfunction plan, required by § 63.6(e)(3), for the source or may be part of a separate document that is maintained at the plant site. In such cases, reasons for delay of repair may be documented by citing the relevant sections of the written procedure. For each source as defined in § 63.101, and for each source as defined in § 63.191, on and after July 15, 2027, the sentence "The written procedures may be included as part of the startup/shutdown/malfunction plan, required by § 63.6(e)(3), for the source or may be part of a separate document that is maintained at the plant site." in this paragraph no longer applies.

* * * * *

(g) * * *

(1) * * *

(iii) Except as specified in paragraph (a) of § 63.108, the flare design (*i.e.,* steam-assisted, air-assisted, or non-assisted) and the results of the compliance demonstration required by § 63.11(b).

* * * * *

(2) * * *

(i) Except as specified in paragraph (a) of § 63.108, dates and durations when the closed-vent systems and control devices required in §§ 63.163 through 63.166, and § 63.170 are not operated as designed as indicated by the monitored parameters, including periods when a flare pilot light system does not have a flame.

* * * * *

(3) Records of inspections of closed-vent systems subject to the provisions of § 63.172, as specified in paragraphs (g)(3)(i) through (iii) of this section.

* * * * *

(iii) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(10), the owner or operator must comply with this paragraph in addition to the requirements in paragraphs (g)(3)(i) and (ii) of this section. For each flow event from a bypass line subject to the requirements in § 63.172(j), the owner or operator must maintain records sufficient to determine whether or not the detected flow included flow requiring control. For each flow event from a bypass line requiring control that is released either directly to the atmosphere or to a control device not meeting the requirements in this subpart, the owner or operator must 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.

* * * * *

(1) For fenceline monitoring systems subject to § 63.184, each owner or operator must keep the records specified in paragraphs (l)(1) through (11) of this section.

(1) Coordinates of all passive tube and canister monitors, including co-located 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.

(2) The start and stop times and dates for each sample, as well as the tube or canister identifying information.

(3) Sampling period average temperature and barometric pressure measurements.

(4) 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. The evidence must include documentation of accidental contamination by the sample handler. High sample results attributed to unknown causes are not outliers if there is no evidence of sample contamination and the sample does not meet the requirements in Section 9.2 of Method 325A of appendix A of this part.

(5) For samples that will be adjusted for offsite impacts, the location of and the concentration measured simultaneously by the additional sampler(s), and the perimeter samplers to which it applies.

(6) Individual sample results, the calculated Δc for each monitored compound for each sampling period and the two samples used to determine it, whether correction for offsite impacts was used, and the annual average Δc for each monitored compound calculated after each sampling period.

(7) Method detection limit for each sample, including co-located samples and blanks.

(8) Documentation of the root cause analysis and any resulting corrective action taken each time an action level is exceeded, including the dates the root cause analysis was initiated and the resulting correction action(s) were taken. If real-time sampling techniques are required under § 63.184(e)(3)(B), the location of the real-time monitors for each 48-hour period.

(9) Any corrective action plan developed under § 63.184(f).

(10) Other records as required by Methods 325A, 325B, and 327 of appendix A of this part.

(11) If monitoring is conducted using canisters in accordance with § 63.184(b), if a near-field source correction is used as provided in § 63.184(g), or if an alternative test method is used that provides time-resolved measurements, 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.

■ 114. Amend § 63.182 by:

■ a. Revising paragraph (a)(3) and adding paragraph (a)(4);

■ b. Revising paragraph (c) introductory text and adding paragraphs (c)(5) and (6);

■ c. Revising paragraphs (d) introductory text and (d)(2) introductory text; and

■ d. Adding paragraphs (d)(2)(xviii) and (xix) and (e).

The revisions and additions read as follows:

§ 63.182 Reporting requirements.

(a) * * *

(3) Periodic Reports described in paragraph (d) of this section,

(4) Fenceline Monitoring Reports described in paragraph (e) of this section, and

* * * * *

(c) Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status within 90 days after the compliance dates specified in the subpart in this part 63 that references this subpart, except as provided in paragraph (c)(4) of this section. The owner or operator shall also submit a supplement to the

Notification of Compliance Status as specified in paragraphs (c)(5) and (6) of this section, if applicable.

* * * * *

(5) For pressure relief devices subject to the pressure release management work practice standards in § 63.165(e), owners and operators must also submit the information listed in paragraphs (c)(5)(i) and (ii) of this section in a supplement to the Notification of Compliance Status within 150 days after the first applicable compliance date for pressure relief device monitoring.

(i) 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.

(ii) A description of the prevention measures to be implemented for each affected pressure relief device.

(6) For equipment that are in ethylene oxide service, as defined in § 63.101, owners and operators must also submit the information in this paragraph in a supplement to the Notification of Compliance Status within 150 days after the first applicable compliance date. The supplement to the Notification of Compliance Status must identify all equipment that are in ethylene oxide service, and include the percent ethylene oxide content of the process fluid and the method used to determine it.

(d) The owner or operator of a source subject to this subpart shall submit Periodic Reports. On and after July 15, 2027 or once the reporting template for this subpart has been available on the CEDRI website for 1 year, whichever date is later, owners and operators must submit all subsequent reports following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Hazardous Organic Chemical Manufacturing Sector Lead. Owners and operators must use the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports under § 63.9(i) and § 63.10(a), the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. All Periodic Reports must include the following general information: company name, address (including county), and beginning and ending dates of the reporting period.

* * * * *

(2) For each process unit complying with the provisions of § 63.163 through § 63.174, the summary information listed in paragraphs (d)(2)(i) through (xix) of this paragraph for each monitoring period during the 6-month period.

* * * * *

(xviii) Compliance reports for pressure relief devices subject to the requirements § 63.165(e) must include the information specified in paragraphs (d)(2)(xviii)(A) through (C) of this section.

(A) For pressure relief devices in organic HAP gas or vapor service, pursuant to § 63.165(e)(1), report the instrument readings and dates for all readings of 500 ppm or greater.

(B) For pressure relief devices in organic HAP gas or vapor service subject to § 63.165(e)(2), report the instrument readings and dates of instrument monitoring conducted.

(C) For pressure relief devices in organic HAP service subject to § 63.165(e)(3), report each pressure release to the atmosphere, including pressure relief device identification name or number, the start date, start time, and duration (in minutes) of the pressure release; an estimate of the mass quantity in pounds of each organic HAP released; 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.

(xix) For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(10), the owner or operator must comply with this paragraph in addition to the requirements in paragraphs (d)(2)(i) through (d)(2)(xviii) of this section. For bypass lines subject to the requirements in § 63.172(j), the Periodic Report must include the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of organic HAP in the gas in parts per million by volume and the resulting mass emissions of organic HAP in pounds that bypass a control device. For periods when the flow indicator is not operating, report the start date, start time, and duration in hours.

* * * * *

(e) For fenceline monitoring systems subject to § 63.184, each owner or operator must submit Fenceline Monitoring Reports on a quarterly basis using the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart and following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Hazardous Organic Chemical Manufacturing Sector Lead. The first quarterly report must be submitted once the owner or operator has obtained 12 months of data. The first quarterly report must cover the period beginning on the compliance date that is specified in § 63.100(k)(12) and ending on March 31, June 30, September 30 or December 31, whichever date is the first date that occurs after the owner or operator has obtained 12 months of data (*i.e.,* the first quarterly report will contain between 12 and 15 months of data). Each subsequent quarterly report must cover one of the following reporting periods: Quarter 1 from January 1 through March 31; Quarter 2 from April 1 through June 30; Quarter 3 from July 1 through September 30; and Quarter 4 from October 1 through December 31. Each quarterly report must be electronically submitted no later than 45 calendar days following the end of the reporting period.

(1) Facility name and address (including the county).

(2) Year and reporting quarter (*i.e.,* Quarter 1, Quarter 2, Quarter 3, or Quarter 4).

(3) For each passive tube or canister monitor: The latitude and longitude location coordinates; the sampler name; and identification of the type of sampler (*i.e.,* regular monitor, extra monitor, duplicate, field blank, inactive). Coordinates must be in decimal degrees with at least five decimal places.

(4) The beginning and ending dates for each sampling period.

(5) Individual sample results for each monitored compound, reported in units of μg/m3, for each monitor for each sampling period that ends during the reporting period. Results below the method detection limit must be flagged as below the detection limit and reported at the method detection limit.

(6) Data flags for each outlier determined in accordance with Section 9.2 of Method 325A of appendix A of this part. For each outlier, the owner or operator must submit the individual sample result of the outlier, as well as the evidence used to conclude that the result is an outlier. The evidence must include documentation of accidental

contamination by the sample handler. High sample results attributed to unknown causes are not outliers if there is no evidence of sample contamination and the sample does not meet the requirements in Section 9.2 of Method 325A of appendix A of this part.

(7) The concentration difference (Δc) for each monitored compound for each sampling period and the annual average Δc for each monitored compound for each sampling period.

(8) Indication of whether the owner or operator was required to develop a corrective action plan under § 63.184(f).

(9) Data flags for each monitor for each analyte that was skipped for the sampling period, if the owner or operator uses an alternative sampling frequency under § 63.184(a)(3)(iii) or § 63.184(b)(2)(iii).

■ 115. Amend § 63.183 by revising paragraph (c) introductory text and adding paragraph (c)(5) to read as follows:

§ 63.183 Implementation and enforcement.

* * * * *

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (5) of this section.

* * * * *

(5) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

■ 116. Add § 63.184 to read as follows:

§ 63.184 Fenceline monitoring provisions.

For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(12), the owner or operator must conduct sampling along the facility property boundary and analyze the samples in accordance with paragraphs (a) through (i) of this section. Sampling of benzene, 1,3-butadiene, chloroprene, and ethylene dichloride must be conducted in accordance with paragraph (a) of this section. Sampling of ethylene oxide and vinyl chloride must be conducted in accordance with paragraph (b) of this section. Paragraphs (c) through (i) of this section apply for any compound required to be sampled.

(a) The owner or operator must conduct sampling along the facility property boundary and analyze the samples in accordance with Methods 325A and 325B of appendix A to this part and paragraphs (a)(1) through (3) of this section. The monitoring perimeter may be located inside the facility, away from the facility property boundary. However, the monitoring perimeter must encompass all potential sources of the target analyte(s) specified in paragraph (a)(1) of this section that are located within the facility's property boundary.

(1) The owner or operator must monitor the target analyte(s), as specified in paragraphs (a)(1)(i) through (iv) of this section. The owner or operator must follow the procedure in Section 9.6 of Method 325B of appendix A to this part to determine the detection limit of benzene, 1,3-butadiene, chloroprene, and ethylene dichloride for each sampler used to collect samples and blanks.

(i) If an affected source uses, produces, stores, or emits benzene, the owner or operator must include benzene as a target analyte.

(ii) If an affected source uses, produces, stores, or emits 1,3-butadiene, the owner or operator must include 1,3-butadiene as a target analyte.

(iii) If an affected source uses, produces, stores, or emits chloroprene, the owner or operator must include chloroprene as a target analyte.

(iv) If an affected source uses, produces, stores, or emits ethylene dichloride, the owner or operator must include ethylene dichloride as a target analyte.

(2) The owner or operator must determine passive monitor locations in accordance with Section 8.2 of Method 325A of appendix A to this part.

(i) As it pertains to this subpart, known sources of VOCs, as used in Section 8.2.1.3 in Method 325A of appendix A to 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. For this subpart, an additional monitor is not required if the only emission sources within 50 meters of the monitoring boundary are equipment leak sources satisfying all of the conditions in paragraphs (a)(2)(i)(A) through (C) of this section. If a leak is found, it must be repaired no later than 15 calendar days after it is detected with no provisions for delay of repair. If a repair is not completed within 15 calendar days, the additional passive monitor specified in Section 8.2.1.3 in Method 325A of appendix A to this part must be used.

(A) The equipment leak sources in organic HAP service within 50 meters of the monitoring boundary are limited to valves, pumps, connectors, sampling connections, and open-ended lines. If compressors, pressure relief devices, or agitators in organic HAP service are present within 50 meters of the monitoring boundary, the additional passive monitoring location specified in Section 8.2.1.3 in Method 325A of appendix A to this part must be used.

(B) All equipment leak sources in gas or light liquid service (and in organic HAP service), including valves, pumps, connectors, sampling connections and open-ended lines, must be monitored using Method 21 of appendix A–7 to 40 CFR part 60 no less frequently than quarterly with no provisions for skip period monitoring, or according to the provisions of § 63.11(c) Alternative Work practice for monitoring equipment for leaks. For the purpose of this provision, a leak is detected if the instrument reading equals or exceeds the applicable limits in paragraphs (a)(2)(i)(B)(*1*) through (*5*) of this section:

(*1*) For valves, pumps or connectors at an existing source, an instrument reading of 10,000 ppmv.

(*2*) For valves or connectors at a new source, an instrument reading of 500 ppmv.

(*3*) For pumps at a new source, an instrument reading of 2,000 ppmv.

(*4*) For sampling connections or open-ended lines, an instrument reading of 500 ppmv above background.

(*5*) For equipment monitored according to the Alternative Work practice for monitoring equipment for leaks, the leak definitions contained in § 63.11(c)(6)(i) through (iii).

(C) All equipment leak sources in organic HAP service, including sources in gas, light liquid and heavy liquid service, must be inspected using visual, audible, olfactory, or any other detection method at least monthly. A leak is detected if the inspection identifies a potential leak to the atmosphere or if there are indications of liquids dripping.

(ii) If there are 19 or fewer monitoring locations, the owner or operator must collect at least one co-located duplicate sample per sampling period and at least one field blank per sampling period. If there are 20 or more monitoring locations, the owner or operator must collect at least two co-located duplicate samples per sampling period and at least one field blank per sampling period. The co-located duplicates may be collected at any of the perimeter sampling.

(iii) Samplers are not required to be placed along internal roads, waterways, or other right of ways that may bisect the facility. If a facility is bounded by a waterway on one or more sides, the shoreline is considered the facility property boundary.

(3) The owner or operator must use a sampling period and sampling frequency as specified in paragraphs (a)(3)(i) through (iii) of this section.

(i) *Sampling period.* A 14-day sampling period must be used, unless a shorter sampling period is determined to be necessary under paragraph (e) or (g) 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 must be 14 calendar days.

(ii) *Base sampling frequency.* Except as provided in paragraph (a)(3)(iii) of this section, the frequency of sample collection must 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.

(iii) *Alternative sampling frequency for burden reduction.* When an individual monitor consistently achieves results for a particular analyte at or below the level specified in paragraph (a)(4) of this section, the owner or operator may elect to use the applicable minimum sampling frequency specified in paragraphs (a)(3)(iii)(A) through (E) of this section for that monitoring site for that analyte. When calculating Δc for the monitoring period when using this alternative for burden reduction, use zero for the lowest sampling result for each monitoring period where one or more samples was not taken and/or analyzed for the analyte(s) that qualifies for this alternative sampling frequency. This alternative for burden reduction is determined on an analyte specific basis. If an owner or operator is not required to sample for a particular analyte for a particular monitoring site in accordance with this paragraph (a)(3)(iii), the owner or operator must still sample for any other analytes required by paragraph (a)(1) of this section at the frequency specified in paragraph (a)(3)(ii) of this section, unless the other analyte(s) also qualifies for this alternative for burden reduction.

(A) For the analyte of interest, if every sample at a monitoring site is at or below the level specified in paragraph (a)(4) of this section for 2 years (52 consecutive samples), every other sampling period can be skipped for that analyte for that monitoring site, *i.e.,* sampling will occur approximately once per month.

(B) For the analyte of interest, if every sample at a monitoring site that is monitored at the frequency specified in paragraph (a)(3)(iii)(A) of this section is at or below the level specified in paragraph (a)(4) of this section for 2 years (*i.e.,* 26 consecutive ''monthly'' samples), five 14-day sampling periods can be skipped for that analyte for that monitoring site following each period of sampling, *i.e.,* sampling will occur approximately once per quarter.

(C) For the analyte of interest, if every sample at a monitoring site that is monitored at the frequency specified in paragraph (a)(3)(iii)(B) of this section is at or below the level specified in paragraph (a)(4) of this section for 2 years (*i.e.,* 8 consecutive quarterly samples), twelve 14-day sampling periods can be skipped for that analyte for that monitoring site following each period of sampling, *i.e.,* sampling will occur twice a year.

(D) For the analyte of interest, if every sample at a monitoring site that is monitored at the frequency specified in paragraph (a)(3)(iii)(C) of this section is at or below the level specified in paragraph (a)(4) of this section for 2 years (*i.e.,* 4 consecutive semiannual samples), only one sample per year is required for that analyte for that monitoring site. For yearly sampling, samples shall occur at least 10 months but no more than 14 months apart.

(E) If at any time a sample for a monitoring site that is monitored for the analyte at the frequency specified in paragraph (a)(3)(iii)(A) through (D) of this section returns a result for the analyte that is above the level specified in paragraph (a)(4) of this section, the sampling site must return to the original sampling requirements for the analyte of contiguous 14-day sampling periods with no skip periods for one quarter (six 14-day sampling periods). If every sample collected for the analyte during this quarter is at or below the level specified in paragraph (a)(4) of this section, the owner or operator may revert back to the reduced monitoring schedule applicable for that analyte for that monitoring site prior to the sample reading exceeding the level specified in paragraph (a)(4) of this section. If any sample collected for the analyte during this quarter is above the level specified in paragraph (a)(4) of this section, that monitoring site must return to the original sampling requirements for that analyte 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 analyte for that monitoring site once the requirements of paragraph (a)(3)(iii)(A) of this section are met again, *i.e.,* after 52 contiguous 14-day samples with no results above the level specified in paragraph (a)(4) of this section.

(4) To use the alternative sampling frequency outlined in paragraph (a)(3) of this section, an individual monitor must consistently achieve results for the analyte at or below the level specified in paragraphs (a)(4)(i) through (iii) of this section.

(i) For benzene, the results must be consistently at or below 0.9 $\mu g/m^3$.

(ii) For 1,3-butadiene, the results must be consistently at or below 0.3 $\mu g/m^3$.

(iii) For ethylene dichloride, the results must be consistently at or below 0.4 $\mu g/m^3$.

(b) The owner or operator must conduct sampling along the facility property boundary and analyze the samples in accordance with Method 327 of appendix A to this part and paragraphs (b)(1) through (3) of this section.

(1) The owner or operator must monitor the target analyte(s), as specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) If an affected source uses, produces, stores, or emits ethylene oxide, the owner or operator must include ethylene oxide as a target analyte.

(ii) If an affected source uses, produces, stores, or emits vinyl chloride, the owner or operator must include vinyl chloride as a target analyte.

(2) The owner or operator must use a sampling period and sampling frequency as specified in paragraphs (b)(2)(i) and (ii) of this section.

(i) *Sampling period.* A 24-hour sampling period must be used, unless a shorter sampling period is determined to be necessary under paragraph (e) or (g) of this section. A sampling period is defined as the period during which the canister is deployed at a specific sampling location and actively sampling and does not include the time required to analyze the sample. For the purpose of this subpart, a 24-hour sampling period may be no shorter than 23 hours and no longer than 25 hours.

(ii) *Base sampling frequency.* Except as provided in paragraph (b)(2)(iii) of this section, the frequency of sample collection must be once every 5 calendar days, such that the beginning of each sampling period begins approximately 96 hours (± 24 hours) from the end of the previous sample.

(iii) *Alternative sampling frequency for burden reduction.* This alternative is only applicable for the measurement of vinyl chloride from sites with a monitoring perimeter less than or equal to 5,000 meters. When an individual sampling point consistently achieves results at or below 0.3 μg/m^3, the owner or operator may elect to use the applicable minimum sampling frequency specified in paragraphs (b)(2)(iii)(A) through (E) of this section for that sampling site for vinyl chloride. If ethylene oxide is a required analyte, the owner or operator must continue to monitor ethylene oxide at the frequency specified in paragraph (b)(2)(ii) of this section. When calculating Δc for the monitoring period when using this alternative for burden reduction, use zero for the lowest sampling result for each monitoring period where one or more samples was not taken for vinyl chloride.

(A) If every sample at a monitoring site is at or below 0.3 μg/m^3 for 2 years (52 consecutive samples), every other sampling period can be skipped for that sampling site, *i.e.,* sampling will occur approximately once per month.

(B) If every sample at a sampling site that is monitored at the frequency specified in paragraph (b)(2)(iii)(A) of this section is at or below 0.3 μg/m^3 for 2 years (*i.e.,* 26 consecutive "monthly" samples), five 14-day sampling periods can be skipped for that sampling site following each period of sampling, *i.e.,* sampling will occur approximately once per quarter.

(C) If every sample at a sampling site that is monitored at the frequency specified in paragraph (b)(2)(iii)(B) of this section is at or below 0.3 μg/m^3 for 2 years (*i.e.,* 8 consecutive quarterly samples), twelve 14-day sampling periods can be skipped for that sampling site following each period of sampling, *i.e.,* sampling will occur twice a year.

(D) If every sample at a sampling site that is monitored at the frequency specified in paragraph (b)(2)(iii)(C) of this section is at or below 0.3 μg/m^3 for 2 years (*i.e.,* 4 consecutive semiannual samples), only one sample per year is required for that sampling site. For yearly sampling, samples shall occur at least 10 months but no more than 14 months apart.

(E) If at any time a sample for a sampling site that is monitored at the frequency specified in paragraphs (b)(2)(iii)(A) through (E) of this section returns a result that is above 0.3 μg/m^3, the sampling site must return to the original sampling requirements of sampling every 5 calendar days with no skip periods for one quarter (18 5-day sampling periods). If every sample collected during this quarter is at or below 0.3 μg/m^3, the owner or operator may revert back to the reduced monitoring schedule applicable for that sampling site prior to the sample reading exceeding 0.3 μg/m^3. If any sample collected during this quarter is above 0.3 μg/m^3, that sampling site must return to the original sampling requirements of sampling every 5 calendar days with no skip periods for a minimum of two years. The burden reduction requirements can be used again for that sampling site once the requirements of paragraph (b)(2)(ii)(A) of this section are met again, *i.e.,* after 146 consecutive samples with no results above 0.3 μg/m^3.

(3) The owner or operator must determine canister sample locations in accordance with paragraphs (b)(3)(i) through (v) of this section.

(i) The monitoring perimeter must be located on or inside the facility property boundary. If the monitoring perimeter is located away from the facility property boundary, the monitoring perimeter must encompass all potential sources of the target analyte(s) specified in paragraph (b)(1) of this section that are located within the facility's property boundary. If the site contains process units that are disconnected (*i.e.,* one or more process areas are not within the boundary of the main facility), the owner or operator must follow the requirements in paragraph (b)(3)(v) of this section. Canisters are not required to be placed along internal roads, waterways, or other right of ways that may bisect the facility. If a facility is bounded by a waterway on one or more sides, the shoreline is considered the facility property boundary.

(ii) The owner or operator must place 8 canisters around the monitoring perimeter during each sampling period.

(iii) To determine sampling locations, measure the length of the monitoring perimeter.

(A) Locate the point on the monitoring perimeter that is closest to sources of the target analyte(s). If one of the target analytes is ethylene oxide, this point must be the point on the monitoring perimeter that is closest to the sources of ethylene oxide.

(B) If the monitoring perimeter is less than or equal to 5,000 meters, divide the monitoring perimeter into 8 evenly spaced sampling points, with one point located in accordance with the requirements of paragraph (b)(3)(iii)(A) of this section.

(C) If the monitoring perimeter is greater than 5,000 meters, but less than or equal to 10,000 meters, divide the monitoring perimeter into 16 evenly spaced sampling points, with one point located in accordance with the requirements of paragraph (b)(3)(iii)(A) of this section.

(D) If the monitoring perimeter is greater than 10,000 meters, divide the monitoring perimeter into 24 evenly spaced sampling points, with one point located in accordance with the requirements of paragraph (b)(3)(iii)(A) of this section.

(iv) Place canisters on the monitoring perimeter at the sampling points as follows.

(A) If there are only 8 sampling points for the site, monitor each sampling point during each sampling period.

(B) If there are 16 sampling points for the site, number the sampling points consecutively along the monitoring perimeter. During the first sampling period, monitor the odd numbered sampling points. During the second sampling period, monitor the even numbered sampling points. Continue to alternate between the odd numbered and even numbered sampling points in subsequent sampling periods.

(C) If there are 24 sampling points for the site, number the sampling points consecutively along the monitoring perimeter. During the first sampling period, monitor every third sampling point starting with the first sampling point (*i.e.,* points 1, 4, 7, etc.). During the second sampling period, monitor every third sampling point starting with the second sampling point (*i.e.,* points 2, 5, 8, etc.). During the third sampling period, monitor every third sampling point starting with the third sampling point (*i.e.,* points 3, 6, 9, etc.). Continue to alternate between these placements for each subsequent sampling period (*i.e.,* the fourth sampling period will include every third sampling point starting with the first sampling point, the fifth sampling period will include every third sampling point starting with the second sampling point, and so on).

(v) If the site consists of small areas disconnected from the main facility, additional monitors must be placed on these areas in accordance with paragraphs (b)(3)(v)(A) through (C) of this section. The monitoring perimeter for the disconnected area(s) must be located between the property boundary of the area and the process unit(s), such that the monitoring perimeter for the disconnected area encompasses all potential sources of the target analyte(s) specified in paragraph (b)(1) of this section.

(A) If the disconnected area is less than 50 acres, the owner or operator must sample at two locations each sampling period. One location must be placed in the expected prevailing wind direction for the sampling period, downwind of the main source of emissions of the target analyte(s). The other location must be located on the monitoring perimeter at 180 degrees from the first sample location.

(B) If the disconnected area is equal to or greater than 50 acres but less than or equal to 150 acres, the owner or operator must sample at four equally spaced locations. One sampling point must be located on the monitoring perimeter at the point that is closest to sources of the target analyte(s). If one of the target analytes is ethylene oxide, this point must be the point on the monitoring perimeter that is closest to the sources of ethylene oxide.

(C) If the disconnected area is greater than 150 acres, the sampling points for the disconnected area must be determined according to paragraphs (b)(3)(ii) through (iv) of this section.

(4) At least one co-located duplicate sample and at least one field blank must be collected per sampling period.

(5) The owner or operator must follow the procedures in Method 327 of appendix A to this part to determine the detection limit of the target analyte(s) and requirements for quality assurance samples.

(c) The owner or operator must collect and record meteorological data according to the applicable requirements in paragraphs (c)(1) through (3) of this section.

(1) If monitoring is conducted under paragraph (b) of this section, if a near-field source correction is used as provided in paragraph (g)(2) of this section, or if an alternative test method is used that provides time-resolved measurements, the owner or operator must use an on-site meteorological station in accordance with Section 8.3 of Method 325A of appendix A to this part. 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 (c)(1) of this section, the owner or operator must 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 to this part or, alternatively, using data from a National Weather Service (NWS) meteorological station provided the NWS meteorological station is within 40 kilometers (25 miles) of the facility.

(3) If an on-site meteorological station is used, the owner or operator must follow the calibration and standardization procedures for meteorological measurements in EPA–454/B–08–002 (incorporated by reference, see § 63.14).

(d) Within 45 days of completion of each sampling period, the owner or operator must determine whether the results are above or below the action level for each measured compound as follows. If the owner or operator is required to monitor any small disconnected area(s) of the facility under paragraph (b)(3)(v) of this section, the procedure for determining whether the results are above or below the action level for each measured compound must be performed for the disconnected area(s) separately.

(1) The owner or operator must determine the facility impact on the concentration (Δc) of each compound for each sampling period according to either paragraph (d)(1)(i) or (ii) of this section, as applicable.

(i) Except when near-field source correction is used as provided in paragraph (d)(1)(ii) of this section, the owner or operator must determine the highest and lowest sample results for each compound individually from the sample pool and calculate each compound's Δc as the difference in these concentrations. Co-located samples must be averaged together for the purposes of determining the concentration at a particular sampling location, and, if applicable, for determining Δc. The owner or operator must adhere to the following procedures when one or more samples for the sampling period are below the method detection limit for a particular compound:

(A) If the lowest detected value of a compound is below detection, the owner or operator must 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 must use the highest method detection limit for the sample set as the highest sample result and zero as the lowest sample result when calculating Δc.

(C) In the case of co-located samples, if one sample is above the method detection limit while the other sample is below the method detection limit, the owner or operator must use the method detection limit as the result for the sample that is below the method detection limit for purposes of averaging the results to determine the concentration at a particular sampling location, and, if applicable, for determining Δc.

(ii) When near-field source correction for a compound is used as provided in paragraph (g) of this section, the owner or operator must determine Δc using the calculation protocols outlined in paragraph (d)(1)(i) of this section, except as provided in this paragraph (d)(1)(ii), and the additional requirements in paragraph (g)(2) of this section, as well as any additional requirements outlined in the approved site-specific monitoring plan. The Δc for the compound for the sampling period is equal to the higher of the values in paragraphs (d)(1)(ii)(A) and (B) of this section.

(A) The highest corrected sample result for the compound from a sampling location where near-field source correction for the compound is used during the sampling period.

(B) The difference in concentration between the highest sample result that was not corrected for a near-field source for the compound during the sampling period and the lowest sample result for the compound for the sampling period.

(2) The owner or operator must calculate the annual average Δc for each monitored compound as follows:

(i) For sampling conducted under paragraph (a) of this section, the annual average Δc for each compound is based on the average of the Δc values for the 26 most recent 14-day sampling periods. The owner or operator must update this annual average value after receiving the results of each subsequent 14-day sampling period.

(ii) For sampling conducted under paragraph (b) of this section, the annual average Δc for each compound is based on the average of the Δc values for the 73 most recent sampling periods. The owner or operator must update this annual average value after receiving the results of each subsequent sampling period.

(3) The action level for each compound is listed in paragraphs (d)(3)(i) through (vi) of this section. If the annual average Δc value for a compound is greater than the listed action level for the compound, the concentration is above the action level, and the owner or operator must conduct a root cause analysis and corrective action in accordance with paragraph (e) of this section.

(i) The action level for benzene is 9 micrograms per cubic meter ($\mu g/m^3$) on an annual average basis.

(ii) The action level for 1,3-butadiene is 3 $\mu g/m^3$ on an annual average basis.

(iii) The action level for chloroprene is 0.8 $\mu g/m^3$ on an annual average basis.

(iv) The action level for ethylene oxide is 0.2 $\mu g/m^3$ on an annual average basis.

(v) The action level for vinyl chloride is 3 $\mu g/m^3$ on an annual average basis.

(vi) The action level for ethylene dichloride is 4 μg/m³ on an annual average basis.

(e) Once any action level in paragraph (d)(3) of this section has been exceeded, the owner or operator must take the following actions to bring the annual average Δc back below the action level(s).

(1) Within 5 days of updating the annual average value as required in paragraph (d)(2) of this section and determining that any action level in paragraph (d)(3) of this section has been exceeded (*i.e.,* in no case longer than 50 days after completion of the sampling period), the owner or operator must initiate a root cause analysis to determine appropriate corrective action. A root cause analysis is an assessment conducted through a process of investigation to determine the primary underlying cause and all other contributing causes to an exceedance of an action level(s) set forth in paragraph (d)(3) of this section.

(i) The initial root cause analysis may include, but is not limited to:

(A) Leak inspection using Method 21 of appendix A–7 to 40 CFR part 60, optical gas imaging, or handheld monitors.

(B) Visual inspection to determine the cause of the high emissions.

(C) Operator knowledge of process changes (*e.g.,* a malfunction or release event).

(ii) If the initial root cause cannot be identified using the type of techniques described in paragraph (e)(1)(i) of this section, the owner or operator must employ more frequent sampling and analysis to determine the root cause of the exceedance.

(A) The owner or operator may first employ additional monitoring points and shorter sampling periods for Methods 325A and 325B of appendix A to this part for benzene, 1,3-butadiene, chloroprene, or ethylene dichloride or more frequent sampling with Method 327 of appendix A to this part for ethylene oxide or vinyl chloride to determine the root cause of the exceedance.

(B) If the owner or operator has not determined the root cause of the exceedance within 30 days of determining that the action level has been exceeded, the owner or operator must employ the appropriate real-time sampling techniques (*e.g.,* mobile gas chromatographs, optical spectroscopy instruments, sensors) to locate the cause of the exceedance. If the root cause is not identified after 48 hours, either the real-time monitor must be relocated or an additional real-time monitor must be added. Relocation or addition of extra real-time monitors must continue after each 48-hour period of nonidentification until the owner or operator can identify the root cause of the exceedance.

(2) If the underlying primary and other contributing causes of the exceedance are deemed to be under the control of the owner or operator, the owner or operator must take appropriate corrective action as expeditiously as possible to bring annual average fenceline concentrations back below the action level(s) set forth in paragraph (d)(3) of this section. At a minimum, the corrective actions taken must address the underlying primary and other contributing cause(s) determined in the root cause analysis to prevent future exceedances from the same underlying cause(s).

(3) The root cause analysis must be completed and initial corrective actions taken no later than 45 days after determining there is an exceedance of an action level.

(4) Until the annual average Δc is below the action level again, following completion of the initial corrective action, the owner or operator must conduct a new root cause analysis according to this paragraph (e), and if required, submit a corrective action plan under paragraph (f) of this section following any sampling period for which the sampling start time begins after the completion of the initial corrective actions and for which the Δc for the sampling period is greater than the level specified in paragraphs (e)(4)(i) through (vi) of this section for the compound(s) that initially exceeded the action level.

(i) For benzene, a sampling period Δc of 9 μg/m³.

(ii) For 1,3-butadiene, a sampling period Δc of 3 μg/m³.

(iii) For chloroprene, a sampling period Δc of 0.8 μg/m³.

(iv) For ethylene dichloride, a sampling period Δc of 4 μg/m³.

(v) For ethylene oxide, a sampling period Δc of 0.2 μg/m³.

(vi) For vinyl chloride, a sampling period Δc of 3 μg/m³.

(f) An owner or operator must develop a corrective action plan if the conditions in paragraphs (f)(1), (2), or (3) of this section are met. The corrective action plan must describe the corrective action(s) completed to date, additional measures that the owner or operator proposes to employ to reduce annual average fenceline concentrations below the action level(s) set forth in paragraph (d)(3) of this section, and a schedule for completion of these measures. The corrective action plan does not need to be approved by the Administrator. However, if upon review, the Administrator disagrees with the additional measures outlined in the plan, the owner or operator must revise and resubmit the plan within 7 calendar days of receiving comments from the Administrator.

(1) If the compound that exceeded the action level was benzene, 1,3-butadiene, chloroprene, or ethylene dichloride, the owner or operator must develop a corrective action plan if, upon completion of the root cause analysis and initial corrective actions required in paragraph (e) of this section, the Δc value for the next sampling period, for which the sampling start time begins after the completion of the initial corrective actions, is greater than the level specified in paragraphs (f)(1)(i) through (iv) of this section for the compound(s) that initially exceeded the action level. The corrective action plan must include the implementation of real-time sampling techniques to locate the primary and other contributing causes of the exceedance. The owner or operator must submit the corrective action plan to the Administrator within 60 days after receiving the analytical results indicating that the Δc value for the sampling period following the completion of the initial corrective action is greater than the level specified in paragraphs (f)(1)(i) through (iv) of this section.

(i) For benzene, a sampling period Δc of 9 μg/m³.

(ii) For 1,3-butadiene, a sampling period Δc of 3 μg/m³.

(iii) For chloroprene, a sampling period Δc of 0.8 μg/m³.

(iv) For ethylene dichloride, a sampling period Δc of 4 μg/m³.

(2) If the compound that exceeded the action level was ethylene oxide or vinyl chloride, the owner or operator must develop a corrective action plan if, upon completion of the root cause analysis and initial corrective actions required in paragraph (e) of this section, the Δc value for any of the next three sampling periods, for which the sampling start time begins after the completion of the initial corrective actions, is greater than the level specified in paragraphs (f)(2)(i) and (ii) of this section for the compound(s) that initially exceeded the action level. The corrective action plan must include the implementation of real-time sampling techniques to locate the primary and other contributing causes of the exceedance. The owner or operator must submit the corrective action plan to the Administrator within 60 days after receiving the analytical results indicating that the Δc value for the sampling period following the completion of the initial corrective

action is greater than the level specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) For ethylene oxide, a sampling period Δc of 0.2 μg/m^3.

(ii) For vinyl chloride, a sampling period Δc of 3 μg/m^3.

(3) The owner or operator must develop a corrective action plan if complete implementation of all corrective measures identified in the root cause analysis required by paragraph (e) of this section will require more than 45 days. The owner or operator must submit the corrective action plan to the Administrator no later than 60 days following the completion of the root cause analysis required in paragraph (e) of this section.

(g) An owner or operator may request approval from the Administrator for a site-specific monitoring plan to account for offsite upwind sources according to the requirements in paragraphs (g)(1) through (4) of this section.

(1) The owner or operator must 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 (g)(2) of this section. The site-specific monitoring plan must include, at a minimum, the elements specified in paragraphs (g)(1)(i) through (vi) of this section. The procedures in Section 12 of Method 325A of appendix A to 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.

(ii) Location of the additional monitoring stations that will be used to determine the near-field source concentration contribution. The owner or operator must use additional monitoring stations to determine the near-field source 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; the treatment of invalid data, data below detection limits, and data collected during calm wind periods; and calculations to determine the near-field source concentration contribution for each monitoring location.

(v) A detailed description of the measurement technique, measurement location(s), the standard operating procedures, measurement frequency, recording frequency, measurement detection limit, and data quality indicators to ensure accuracy, precision, and validity of the data.

(vi) A detailed description of how data will be handled during periods of calm wind conditions (*i.e.,* less than 2 miles per hour).

(2) When an approved site-specific monitoring plan is used, the owner or operator must determine Δc for comparison with the action level according to paragraph (d) of this section. When determining the highest and lowest sample results for use in the Δc calculation, the concentration for any monitor that has been corrected using an approved site-specific monitoring plan will be corrected according to the procedures specified in paragraphs (g)(2)(i) and (ii) of this section.

(i) For each monitoring location corrected using the site-specific monitoring plan, the corrected fenceline concentration at that monitoring station will be equal to the fenceline concentration measured with Methods 325A and 325B or Method 327 of appendix A to this part minus the near-field source contributing concentration at the measurement location determined using the additional measurements and calculation procedures included in the site-specific monitoring plan.

(ii) If the fenceline concentration at the monitoring station is below the method detection limit for Methods 325A and 325B or Method 327 of appendix A to this part, no near-field source contribution can be subtracted from that monitoring station for that sampling period.

(3) The site-specific monitoring plan must be submitted and approved as described in paragraphs (g)(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 must 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: Hazardous Organic Chemical Manufacturing Sector Lead, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *fencelineplan@epa.gov.*

(iii) The Administrator will approve or disapprove the plan in 90 days. The plan is considered approved if the Administrator either approves the plan in writing or fails to disapprove the plan in writing. The 90-day period begins 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 (g)(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 (g)(4)(i) through (v) of this section.

(i) The identification of the near-field source or sources and evidence of how the sources impact the fenceline concentrations.

(ii) The location(s) selected for additional monitoring to determine the near-field source concentration contribution.

(iii) The identification of the fenceline monitoring locations impacted by the near-field source or sources.

(iv) The appropriateness of the planned data reduction and calculations to determine the near-field source concentration contribution for each monitoring location, including the handling of invalid data, data below the detection limit, and data during calm periods.

(v) The adequacy of the description of and rationale for the measurement technique, measurement location(s), the standard operation procedure, measurement frequency, recording frequency, measurement detection limit, and data quality indicators to ensure accuracy, precision, and validity of the data.

(h) The owner or operator must comply with the applicable recordkeeping and reporting requirements in §§ 63.181 and 63.182.

(i) 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 (i)(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 to this part or the canister sampling locations required under paragraph (b) of this section.

(2) The alternative method must be validated according to Method 301 in

appendix A to this part or contain performance-based procedures and indicators to ensure self-validation.

(3) The method detection limit must nominally be at least one-third of the action level for the compound(s) that will be monitored with the alternative method. The alternate test method must describe the procedures used to provide field verification of the detection limit.

(4) If the alternative test method will be used to replace some or all passive samplers required under paragraph (a) of this section, the spatial coverage must be equal to or better than the spatial coverage provided in Method 325A of appendix A to this part. If the alternative test method will be used to replace some or all canisters required under paragraph (b) of this section, the spatial coverage must be equal to or better than the spatial coverage provided under paragraph (b) of this section.

(i) For path average concentration open-path instruments, the physical path length of the measurement must be no more than a passive sample footprint (the spacing that would be provided by the sorbent traps when following Method 325A of appendix A to this part) or canister sample footprint, as applicable. For example, if Method 325A requires spacing monitors A and B 610 meters (2,000 feet) apart, then the physical path length limit for the measurement at that portion of the fenceline must be no more than 610 meters (2,000 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 or canister sample footprint within the path length of the instrument.

(iii) The extra samplers required in Sections 8.2.1.3 of Method 325A of appendix A to this part 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 individual sampling period, all results measured under the method detection limit must use the method detection limit. For purposes of averaging data points for the individual sampling period low sample result, all results measured under the method detection limit must use zero.

■ 117. Revise tables 1 through 4 to subpart H to read as follows:

TABLE 1 TO SUBPART H OF PART 63—BATCH PROCESSES

[Monitoring frequency for equipment other than connectors]

Operating time (% of year)	Equivalent continuous process monitoring frequency time in use		
	Monthly	Quarterly	Semiannually
0 to <25	Quarterly	Annually	Annually.
25 to <50	Quarterly	Semiannually	Annually.
50 to <75	Bimonthly	Three times	Semiannually.
75 to 100	Monthly	Quarterly	Semiannually.

TABLE 2 TO SUBPART H OF PART 63—SURGE CONTROL VESSELS AND BOTTOMS RECEIVERS AT EXISTING SOURCES

Vessel capacity (cubic meters)	Vapor pressure[1] (kilopascals)
75 ≤ capacity <151	≥13.1
151 ≤ capacity	[a]≥5.2

[1] Maximum true vapor pressure of total organic HAP at operating temperature as defined in subpart G of this part.

TABLE 3 TO SUBPART H OF PART 63—SURGE CONTROL VESSELS AND BOTTOMS RECEIVERS AT NEW SOURCES

Vessel capacity (cubic meters)	Vapor pressure[1] (kilopascals)
38 ≤ capacity <151	≥13.1
151 ≤ capacity	≥0.7

[1] Maximum true vapor pressure of total organic HAP at operating temperature as defined in subpart G of this part.

TABLE 4 TO SUBPART H OF PART 63—APPLICABLE 40 CFR PART 63 GENERAL PROVISIONS

40 CFR part 63, subpart A, provisions applicable to subpart H
§ 63.1(a)(1), (a)(2), (a)(3), (a)(13), (a)(14), (b)(2) and (c)(4).
§ 63.2.
§ 63.5(a)(1), (a)(2), (b), (d)(1)(ii), (d)(4), (e), (f)(1) and (f)(2).
§ 63.6(a), (b)(3), (c)(5), (i)(1), (i)(2), (i)(4)(i)(A), (i)(5) through (i)(14), (i)(16) and (j).
§ 63.9(a)(2), (b)(4)(i),[a] (b)(4)(ii), (b)(4)(iii), (b)(5),[a] (c), (d), (j) and (k).
§ 63.10(d)(4).
§ 63.11 (c), (d), and (e).

TABLE 4 TO SUBPART H OF PART 63—APPLICABLE 40 CFR PART 63 GENERAL PROVISIONS—Continued

40 CFR part 63, subpart A, provisions applicable to subpart H
§ 63.12(b).

[a] The notifications specified in § 63.9(b)(4)(i) and (b)(5) shall be submitted at the times specified in 40 CFR part 65.

■ 118. Revise the heading to subpart I to read as follows:

Subpart I—National Emission Standards for Hazardous Air Pollutants for Certain Processes Subject to the Negotiated Regulation for Equipment Leaks

■ 119. Amend § 63.192 by:

■ a. Revising paragraphs (b)(6), (7) and (10), and adding paragraph (b)(12); revising paragraph (c)(3) and adding paragraph (c)(5); and

■ b. Revising and republishing paragraph (f)(2) and revising (g) introductory text.

The revisions, additions and republication read as follows:

§ 63.192 Standard.

* * * * *

(b) * * *

(6)(i) Except as specified in paragraph (b)(12) of this section, the compliance with standards and maintenance requirements of § 63.6(a), (b)(3), (c)(5), (e), (i)(1), (i)(2), (i)(4)(i)(A), (i)(6)(i), (i)(8) through (i)(10), (i)(12) through (i)(14), (i)(16), and (j);

(ii) Except as specified in paragraph (b)(12) of this section, the operational and maintenance requirements of § 63.6(e). The startup, shutdown, and malfunction plan requirement of § 63.6(e)(3) is limited to control devices subject to the provisions of subpart H of this part and is optional for other equipment subject to subpart H. The startup, shutdown, and malfunction plan may include written procedures that identify conditions that justify a delay of repair. On and after July 15, 2027, the last two sentences of this paragraph do not apply.

(7) With respect to flares, except as specified in paragraph (b)(12) of this section, the performance testing requirements of § 63.7(a)(3), (d), (e)(1), (e)(2), (e)(4), and (h);

* * * * *

(10) Except as specified in paragraph (b)(12) of this section, the control device requirements of § 63.11(b); and

* * * * *

(12) On and after July 15, 2027, § 63.6(e)(1)(i), (e)(1)(ii), and (e)(3), § 63.7(e)(1), and § 63.11(b) do not apply. Instead, you must comply with paragraphs (b)(12)(i) through (iii) of this section.

(i) The owner or operator of a source subject to this subpart shall comply with the requirements at all times, except during periods of nonoperation of the source (or specific portion thereof) resulting in cessation of the emissions to which this subpart or subpart H of this part applies.

(ii) At all times, owners and operators subject to this subpart must operate and maintain any 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 owners and operators 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.

(iii) Owners and operators that use a flare to comply with this subpart must comply with § 63.108.

(c) * * *

(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 conditions for the process except as specified in paragraph (c)(5) of this section. During the performance test, an owner or operator may operate the control or recovery device at maximum or minimum representative operating conditions for monitored control or recovery device parameters, whichever results in lower emission reduction.

* * * * *

(5) On and after July 15, 2027, in lieu of the requirements specified in § 63.7(e)(1) you must conduct performance tests under such conditions as the Administrator specifies based on representative performance of the affected source for the period being tested. Representative conditions exclude periods of startup and shutdown. 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 such conditions represent normal operation. Upon request, you must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

* * * * *

(f) * * *

(2) The owner or operator subject to subparts I and H of this part shall keep the records specified in this paragraph, as well as records specified in subpart H of this part.

(i) Records of the occurrence and duration of each start-up, shutdown, and malfunction of operation of a process subject to this subpart as specified in § 63.190(b). On and after July 15, 2027, this paragraph no longer applies; however, for historical compliance purposes, a copy of these records must be retained and available on-site for at least five years after the date of occurrence.

(ii) Records of the occurrence and duration of each malfunction of air pollution control equipment or continuous monitoring systems used to comply with subparts I and H of this part.

(iii) For each start-up, shutdown, and malfunction, records that the procedures specified in the source's start-up, shutdown, and malfunction plan were followed, and documentation of actions taken that are not consistent with the plan. These records may take the form of a "checklist," or other form of recordkeeping that confirms conformance with the startup, shutdown, and malfunction plan for the event. On and after July 15, 2027, this paragraph no longer applies; however, for historical compliance purposes, a copy of the plan and these records must be retained and available on-site for at least five years after the date of occurrence.

(g) All reports required under subpart H shall be submitted as required in § 63.182.

* * * * *

■ 120. Amend § 63.480 by revising paragraphs (j) introductory text and (j)(4) introductory text as follows:

§ 63.480 Applicability and designation of affected sources.

* * * * *

(j) *Applicability of this subpart.* Paragraphs (j)(1) through (3) of this section must be followed during periods of non-operation of the affected source or any part thereof.

* * * * *

(4) Beginning on July 15, 2024, this paragraph (j)(4) no longer applies. In response to an action to enforce the standards set forth in this subpart, an owner or operator may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by a malfunction, as defined in § 63.2. Appropriate penalties may be assessed, however, if the owner or operator fails to meet the burden of proving all the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

* * * * *

■ 121. Amend § 63.481 by revising paragraph (a), (b), (c) introductory text, (d) introductory text, (k), and adding paragraphs (k)(2) and (n) through (p) as follows:

§ 63.481 Compliance dates and relationship of this subpart to existing applicable rules.

(a) Affected sources are required to achieve compliance on or before the dates specified in paragraphs (b) through (d) of this section and paragraphs (n) and (o) of this section. Paragraph (e) of this section provides information on requesting compliance extensions. Paragraphs (f) through (l) of this section discuss the relationship of this subpart to subpart A and to other applicable rules. Where an override of another authority of the Act is indicated in this subpart, only compliance with the provisions of this subpart is required. Paragraph (m) of this section specifies the meaning of time periods.

(b) Except as specified in paragraphs (n) and (o) of this section, new affected sources that commence construction or reconstruction after June 12, 1995 shall be in compliance with this subpart upon initial start-up or by June 19, 2000, whichever is later.

(c) With the exceptions provided in paragraphs (c)(1) through (3) of this section and paragraphs (n) and (o) of this section, existing affected sources shall be in compliance with this subpart no later than June 19, 2001, as provided in § 63.6(c), unless an extension has been granted as specified in paragraph (e) of this section.

* * * * *

(d) Except as provided for in paragraphs (d)(1) through (d)(6) of this section, and paragraphs (n) and (o) of this section, existing affected sources shall be in compliance with § 63.502 no later than July 31, 1997, unless an extension has been granted pursuant to paragraph (e) of this section.

* * * * *

(k) *Applicability of other regulations for monitoring, recordkeeping or reporting with respect to combustion devices, recovery devices, or recapture devices.* (1) After the compliance dates specified in this subpart, if any combustion device, recovery device or recapture device subject to this subpart is also subject to monitoring, recordkeeping, and reporting requirements in 40 CFR part 264 subpart AA or CC, or is subject to monitoring and recordkeeping requirements in 40 CFR part 265 subpart AA or CC and the owner or operator complies with the periodic reporting requirements under 40 CFR part 264 subpart AA or CC that would apply to the device if the facility had final-permitted status, the owner or operator may elect to comply either with the monitoring, recordkeeping and reporting requirements of this subpart, or with the monitoring, recordkeeping and reporting requirements in 40 CFR parts 264 and/or 265, as described in this paragraph, which shall constitute compliance with the monitoring, recordkeeping and reporting requirements of this subpart. The owner or operator shall identify which option has been selected in the Notification of Compliance Status required by § 63.506(e)(5).

(2) Owners and operators of flares that are subject to the flare related requirements of this subpart and are also subject to flare related requirements of any other regulation in this part or 40 CFR part 61 or 63, may elect to comply with the requirements in § 63.508 in lieu of all flare related requirements in any other regulation in this part or 40 CFR part 61 or 63.

* * * * *

(n) All affected sources that commenced construction or reconstruction on or before April 25, 2023, must be in compliance with the requirements listed in paragraphs (n)(1) through (9) of this section upon initial startup or on July 15, 2027, whichever is later. All affected sources that commenced construction or reconstruction after April 25, 2023, must be in compliance with the requirements listed in paragraphs (n)(1) through (9) of this section upon initial startup, or on July 15, 2024, whichever is later.

(1) The general requirements specified in § 63.483(e), § 63.504(a), § 63.504(a)(1)(iii), and § 63.506(e)(6)(iii)(C).

(2) For flares, the requirements specified in § 63.508.

(3) For storage vessels, the requirements specified in § 63.484(t) and § 63.506(e)(4)(ii)(F)(*6*).

(4) For continuous front-end process vents, the requirements specified in §§ 63.485(l)(6), (o)(6), (p)(5), (q)(1)(vii), (x), § 63.503(g)(2)(iii)(B)(*4*), and § 63.506(e)(4)(ii)(F)(*6*).

(5) For batch front-end process vents, the requirements specified in §§ 63.487(a)(3), (b)(3), and (e)(1)(iv) and (i), §§ 63.488(d)(2), (e)(4), (f)(2), and (g)(3), §§ 63.489(b)(10) and (d)(3), §§ 63.491(d)(1)(iii), (e)(6), and (h), § 63.492(g), and Table 6 to this subpart, item 3 in column 3 for diversion to the atmosphere and monthly inspections of sealed valves for all control devices.

(6) For back-end processes, the requirements specified in §§ 63.497(a)(8) and (d)(3), and § 63.498(d)(5)(v).

(7) For wastewater, the requirements specified in §§ 63.501(d), (e), and (f).

(8) For equipment leaks, the requirements specified in §§ 63.502(a)(2) and (k)(2).

(9) For heat exchange systems, the requirements specified in §§ 63.502(n)(7) and (n)(8).

(o) All affected sources that commenced construction or reconstruction on or before April 25, 2023, must be in compliance with the chloroprene requirements in §§ 63.484(u), 63.485(y) and (z), 63.487(j), 63.494(a)(7), 63.501(a)(10)(iv), 63.502(a)(3) and (a)(7), 63.509, and 63.510 upon initial startup or on October 15, 2024, whichever is later. All affected sources that commenced construction or reconstruction after April 25, 2023, must be in compliance with the chloroprene requirements in §§ 63.484(u), 63.485(x) and (z), 63.487(j), 63.494(a)(7), § 63.501(a)(10)(iv), 63.502(q), 63.502(a)(3) and (a)(7), 63.509, and 63.510 upon initial startup, or on July 15, 2024, whichever is later.

(p) The compliance schedule for fenceline monitoring is specified in paragraphs (p)(1) and (2) of this section.

(1) Except as specified in paragraph (p)(2) of this section, all affected sources that commenced construction or reconstruction on or before April 25, 2023, must commence fenceline monitoring according to the requirements in § 63.502(a)(4) by no later than July 15, 2026, however requirements for corrective actions are not required until on or after July 15, 2027. All affected sources that commenced construction or

reconstruction after April 25, 2023, must be in compliance with the fenceline monitoring requirements listed in § 63.502(a)(4) upon initial startup, or on July 15, 2024, whichever is later.

(2) For affected sources producing neoprene, the compliance schedule specified in paragraph (p)(1) of this section does not apply for chloroprene. Instead, all affected sources producing neoprene that commenced construction or reconstruction on or before April 25, 2023, must be in compliance with the fenceline monitoring requirements for chloroprene listed in § 63.502(a)(4) and (a)(7) upon initial startup or on October 15, 2024, whichever is later. All affected sources producing neoprene that commenced construction or reconstruction after April 25, 2023, must be in compliance with the fenceline monitoring requirements for chloroprene listed in § 63.502(a)(4) and (a)(7) upon initial startup, or on July 15, 2024, whichever is later.

■ 122. Revise and republish § 63.482 to read as follows:

§ 63.482 Definitions.

(a) The following terms used in this subpart shall have the meaning given them in § 63.2, § 63.101, or the Act, as specified after each term:

Act (§ 63.2)
Administrator (§ 63.2)
Automated monitoring and recording system (§ 63.101)
Boiler (§ 63.101)
Bottoms receiver (§ 63.101)
Breakthrough (§ 63.101)
By compound (§ 63.101)
By-product (§ 63.101)
Car-seal (§ 63.101)
Closed-vent system (§ 63.101)
Combustion device (§ 63.101)
Commenced (§ 63.2)
Compliance date (§ 63.2)
Connector (§ 63.101)
Continuous monitoring system (§ 63.2)
Distillation unit (§ 63.101)
Duct work (§ 63.101)
Emission limitation (Section 302(k) of the Act)
Emission standard (§ 63.2)
Emissions averaging (§ 63.2)
EPA (§ 63.2)
Equipment leak (§ 63.101)
External floating roof (§ 63.101)
Fill or filling (§ 63.101)
Fixed capital cost (§ 63.2)
Flame zone (§ 63.101)
Floating roof (§ 63.101)
Flow indicator (§ 63.101)
Fuel gas system (§ 63.101)
Halogens and hydrogen halides (§ 63.101)
Hard-piping (§ 63.101)
Hazardous air pollutant (§ 63.2)
Heat exchange system (§ 63.101)
Impurity (§ 63.101)
Incinerator (§ 63.101)
In organic hazardous air pollutant service or in organic HAP service (§ 63.101)
Instrumentation system (§ 63.101)
Internal floating roof (§ 63.101)
Lesser quantity (§ 63.2)
Major source (§ 63.2)
Malfunction (§ 63.2)
Oil-water separator or organic-water separator (§ 63.101)
Open-ended valve or line (§ 63.101)
Operating permit (§ 63.101)
Organic monitoring device (§ 63.101)
Owner or operator (§ 63.2)
Performance evaluation (§ 63.2)
Performance test (§ 63.2)
Permitting authority (§ 63.2)
Plant site (§ 63.101)
Potential to emit (§ 63.2)
Pressure release (§ 63.101)
Primary fuel (§ 63.101)
Pressure release (§ 63.101)
Pressure relief device (§ 63.101)
Pressure vessel (§ 63.101)
Process heater (§ 63.101)
Process unit shutdown (§ 63.101)
Process wastewater (§ 63.101)
Process wastewater stream (§ 63.101)
Reactor (§ 63.101)
Recapture device (§ 63.101)
Relief valve (§ 63.101)
Repaired (§ 63.101)
Research and development facility (§ 63.101)
Routed to a process or route to a process (§ 63.101)
Run (§ 63.2)
Secondary fuel (§ 63.101)
Sensor (§ 63.101)
Specific gravity monitoring device (§ 63.101)
Start-up, shutdown, and malfunction plan (§ 63.101) On and after July 15, 2027, this definition no longer applies.
State (§ 63.2)
Stationary Source (§ 63.2)
Surge control vessel (§ 63.101)
Temperature monitoring device (§ 63.101)
Test method (§ 63.2)
Treatment process (§ 63.101)
Unit operation (§ 63.101)
Visible emission (§ 63.2)
Secondary fuel (§ 63.101)
Sensor (§ 63.101)
Specific gravity monitoring device (§ 63.101)
Start-up, shutdown, and malfunction plan (§ 63.101) On and after July 15, 2027, this definition no longer applies.
State (§ 63.2)
Stationary Source (§ 63.2)
Surge control vessel (§ 63.101)
Temperature monitoring device (§ 63.101)
Test method (§ 63.2)
Treatment process (§ 63.101)
Unit operation (§ 63.101)
Visible emission (§ 63.2)

(b) All other terms used in this subpart shall have the meaning given them in this section. If a term is defined in a subpart referenced in this section, it shall have the meaning given in this section for purposes of this subpart.

Affected source is defined in § 63.480(a).

Affirmative defense means, in the context of an enforcement proceeding, a response or a defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding. Beginning on July 15, 2024, this definition of *affirmative defense* no longer applies.

Aggregate batch vent stream means a gaseous emission stream containing only the exhausts from two or more batch front-end process vents that are ducted, hard-piped, or otherwise connected together for a continuous flow.

Annual average batch vent concentration is determined using Equation 17, as described in § 63.488(h)(2) for halogenated compounds.

Annual average batch vent flow rate is determined by the procedures in § 63.488(e)(3).

Annual average concentration, as used in the wastewater provisions, means the flow-weighted annual average concentration, as determined according to the procedures specified in § 63.144(b), with the exceptions noted in § 63.501, for the purposes of this subpart.

Annual average flow rate, as used in the wastewater provisions, means the annual average flow rate, as determined according to the procedures specified in § 63.144(c), with the exceptions noted in § 63.501, for the purposes of this subpart.

Average batch vent concentration is determined by the procedures in § 63.488(b)(5)(iii) for HAP concentrations and is determined by the procedures in § 63.488(h)(1)(iii) for organic compounds containing halogens and hydrogen halides.

Average batch vent flow rate is determined by the procedures in § 63.488(e)(1) and (2).

Back-end refers to the unit operations in an EPPU following the stripping operations. Back-end process operations include, but are not limited to, filtering, coagulation, blending, concentration, drying, separating, and other finishing operations, as well as latex and crumb storage. Back-end does not include storage and loading of finished product or emission points that are regulated under § 63.484, § 63.501, or § 63.502.

Batch cycle means the operational step or steps, from start to finish, that occur as part of a batch unit operation.

Batch emission episode means a discrete emission venting episode associated with a single batch unit operation. Multiple batch emission episodes may occur from a single batch unit operation.

Batch front-end process vent means a process vent with annual organic HAP emissions greater than 225 kilograms per year from a batch unit operation within an affected source and located in the front-end of a process unit. Annual organic HAP emissions are determined as specified in § 63.488(b) at the location specified in § 63.488(a)(2).

Batch mass input limitation means an enforceable restriction on the total mass of HAP or material that can be input to a batch unit operation in one year.

Batch mode means the discontinuous bulk movement of material through a unit operation. Mass, temperature, concentration, and other properties may vary with time. For a unit operation operated in a batch mode (*i.e.,* batch unit operation), the addition of material and withdrawal of material do not typically occur simultaneously.

Batch process means, for the purposes of this subpart, a process where the reactor(s) is operated in a batch mode.

Batch unit operation means a unit operation operated in a batch mode.

Block polymer means a polymer where the polymerization is controlled, usually by performing discrete polymerization steps, such that the final polymer is arranged in a distinct pattern of repeating units of the same monomer.

Butyl rubber means a copolymer of isobutylene and other monomers. Typical other monomers include isoprene and methylstyrene. A typical composition of butyl rubber is approximately 85- to 99-percent isobutylene, and 1- to 15-percent other monomers. Most butyl rubber is produced by precipitation polymerization, although other methods may be used. Halobutyl rubber is a type of butyl rubber elastomer produced using halogenated copolymers.

Combined vent stream, as used in reference to batch front-end process vents, continuous front-end process vents, and aggregate batch vent streams, means the emissions from a combination of two or more of the aforementioned types of process vents. The primary occurrence of a combined vent stream is as combined emissions from a continuous front-end process vent and a batch front-end process vent.

Combustion device burner means a device designed to mix and ignite fuel and air to provide a flame to heat and oxidize waste organic vapors in a combustion device.

Compounding unit means a unit operation which blends, melts, and resolidifies solid polymers for the purpose of incorporating additives, colorants, or stabilizers into the final elastomer product. A unit operation whose primary purpose is to remove residual monomers from polymers is not a compounding unit.

Construction means the on-site fabrication, erection, or installation of an affected source. Construction also means the on-site fabrication, erection, or installation of a process unit or combination of process units which subsequently becomes an affected source or part of an affected source, due to a change in primary product.

Continuous front-end process vent means a process vent located in the front-end of a process unit and containing greater than 0.005 weight percent total organic HAP from a continuous unit operation within an affected source. The total organic HAP weight percent is determined after the last recovery device, as described in § 63.115(a), and is determined as specified in § 63.115(c).

Continuous mode means the continuous movement of material through a unit operation. Mass, temperature, concentration, and other properties typically approach steady-state conditions. For a unit operation operated in a continuous mode (*i.e.,* continuous unit operation), the simultaneous addition of raw material and withdrawal of product is typical.

Continuous process means, for the purposes of this subpart, a process where the reactor(s) is operated in a continuous mode.

Continuous record means documentation, either in hard copy or computer readable form, of data values measured at least once every 15 minutes and recorded at the frequency specified in § 63.506(d) or (h).

Continuous recorder means a data recording device that either records an instantaneous data value at least once every 15 minutes or records 1—hour or more frequent block average values.

Continuous unit operation means a unit operation operated in a continuous mode.

Control device is defined in § 63.111, except that the term ‘‘continuous front-end process vent’’ shall apply instead of the term ‘‘process vent,’’ for the purpose of this subpart.

Crumb rubber dry weight means the weight of the polymer, minus the weight of water and residual organics.

Dioxins and furans means total tetra- through octachlorinated dibenzo-p-dioxins and dibenzofurans.

Drawing unit means a unit operation which converts polymer into a different shape by melting or mixing the polymer and then pulling it through an orifice to create a continuously extruded product.

Elastomer means any polymer having a glass transition temperature lower than −10 °C, or a glass transition temperature between −10 °C and 25 °C that is capable of undergoing deformation (stretching) of several hundred percent and recovering essentially when the stress is removed. For the purposes of this subpart, resins are not considered to be elastomers.

Elastomer product means one of the following types of products, as they are defined in this section:

(i) Butyl Rubber;

(ii) Epichlorohydrin Elastomer;

(iii) Ethylene Propylene Rubber;

(iv) Hypalon™;

(v) Neoprene;

(vi) Nitrile Butadiene Rubber;

(vii) Nitrile Butadiene Latex;

(viii) Polybutadiene Rubber/Styrene Butadiene Rubber by Solution;

(ix) Polysulfide Rubber;

(x) Styrene Butadiene Rubber by Emulsion; and

(xi) Styrene Butadiene Latex.

Elastomer product process unit (EPPU) means a collection of equipment assembled and connected by hard-piping or duct work, used to process raw materials and to manufacture an elastomer product as its primary product. This collection of equipment includes unit operations; recovery operations equipment; process vents; storage vessels, as determined in § 63.480(g); equipment that is identified in § 63.149; and the equipment that is subject to the equipment leak provisions as specified in § 63.502. Utilities, lines and equipment not containing process fluids, and other non-process lines, such as heating and cooling systems which do not combine their materials with those in the processes they serve, are not part of an elastomer product process unit. An elastomer product process unit consists of more than one unit operation.

Elastomer type means one of the elastomers listed under ‘‘elastomer product’’ in this section. Each elastomer identified in that definition represents a different elastomer type.

Emission point means an individual continuous front-end process vent, batch front-end process vent, back-end process vent, storage vessel, waste management unit, heat exchange system, or equipment leak, or equipment subject to § 63.149.

Emulsion process means a process where the monomer(s) is dispersed in droplets throughout a water phase, with the aid of an emulsifying agent such as soap or a synthetic emulsifier. The polymerization occurs either within the emulsion droplet or in the aqueous phase.

Epichlorohydrin elastomer means an elastomer formed from the polymerization or copolymerization of epichlorohydrin (EPI). The main epichlorohydrin elastomers are polyepichlorohydrin, epi-ethylene oxide (EO) copolymer, epi-allyl glycidyl ether (AGE) copolymer, and epi-EO-AGE terpolymer. Epoxies produced by the copolymerization of EPI and bisphenol A are not epichlorohydrin elastomers.

Equipment means, for the purposes of the provisions in § 63.502(a) through (m) and the requirements in subpart H that are referred to in § 63.502(a) through (m), each pump, compressor, agitator, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, surge control vessel, bottoms receiver, and instrumentation system in organic hazardous air pollutant service; and any control devices or systems required by subpart H of this part.

Ethylene-propylene rubber means an ethylene-propylene copolymer or an ethylene-propylene terpolymer. Ethylene-propylene copolymers (EPM) result from the polymerization of ethylene and propylene and contain a saturated chain of the polymethylene type. Ethylene-propylene terpolymers (EPDM) are produced in a similar manner as EPM, except that a third monomer is added to the reaction sequence. Typical third monomers include ethylidene norbornene, 1,4-hexadiene, or dicyclopentadiene. Ethylidene norbornene is the most commonly used. The production process includes, but is not limited to, polymerization, recycle, recovery, and packaging operations. The polymerization reaction may occur in either a solution process or a suspension process.

Existing affected source is defined in § 63.480(a)(3).

Existing process unit means any process unit that is not a new process unit.

Extruding unit means a unit operation which converts polymer into a different shape by melting or mixing the polymer and then forcing it through an orifice to create a continuously extruded product.

Flexible operation unit means a process unit that manufactures different chemical products, polymers, or resins periodically by alternating raw materials or operating conditions. These units are also referred to as campaign plants or blocked operations.

Front-end refers to the unit operations in an EPPU prior to, and including, the stripping operations. For all gas-phased reaction processes, all unit operations are considered to be front-end.

Gas-phased reaction process means an elastomer production process where the reaction occurs in a gas phase, fluidized bed.

Glass transition temperature means the temperature at which an elastomer polymer becomes rigid and brittle.

Grade means a group of recipes of an elastomer type having similar characteristics such as molecular weight, monomer composition, significant mooney values, and the presence or absence of extender oil and/or carbon black. More than one recipe may be used to produce the same grade.

Group 1 batch front-end process vent means, before July 15, 2027, a batch front-end process vent releasing annual organic HAP emissions greater than or equal to 11,800 kg/yr and with a cutoff flow rate, calculated in accordance with § 63.488(f), greater than or equal to the annual average batch vent flow rate. Annual organic HAP emissions and annual average batch vent flow rate are determined at the exit of the batch unit operation, as described in § 63.488(a)(2). Annual organic HAP emissions are determined as specified in § 63.488(b), and annual average batch vent flow rate is determined as specified in § 63.488(e). On and after July 15, 2027, Group 1 batch front-end process vent means, each batch front-end process vent that, when combined, the sum of all these process vents would release annual organic HAP emissions greater than or equal to 4,536 kg/yr (10,000 lb/yr) as determined using the procedures specified in § 63.488(b).

Group 2 batch front-end process vent means a batch front-end process vent that does not fall within the definition of a Group 1 batch front-end process vent.

Group 1 continuous front-end process vent means, before July 15, 2027, a continuous front-end process vent for which the flow rate is greater than or equal to 0.005 standard cubic meter per minute, the total organic HAP concentration is greater than or equal to 50 parts per million by volume, and the total resource effectiveness index value, calculated according to § 63.115, is less than or equal to 1.0. On and after July 15, 2027, Group 1 continuous front-end process vent means a process vent that emits greater than or equal to 1.0 pound per hour of total organic HAP.

Group 2 continuous front-end process vent means, before July 15, 2027, a continuous front-end process vent for which the flow rate is less than 0.005 standard cubic meter per minute, the total organic HAP concentration is less than 50 parts per million by volume, or the total resource effectiveness index value, calculated according to § 63.115, is greater than 1.0. On and after July 15, 2027, Group 2 continuous front-end process vent means a process vent that emits less than 1.0 pound per hour of total organic HAP.

Group 1 storage vessel means a storage vessel at an existing affected source that meets the applicability criteria specified in Table 3 of this subpart, or a storage vessel at a new affected source that meets the applicability criteria specified in Table 4 of this subpart.

Group 2 storage vessel means a storage vessel that does not fall within the definition of a Group 1 storage vessel.

Group 1 wastewater stream means a wastewater stream consisting of process wastewater from an existing or new affected source that meets the criteria for Group 1 status in § 63.132(c), with the exceptions listed in § 63.501(a)(10) for the purposes of this subpart (*i.e.,* for organic HAP as defined in this section).

Group 2 wastewater stream means any process wastewater stream that does not meet the definition of a Group 1 wastewater stream.

Halogenated aggregate batch vent stream means an aggregate batch vent stream determined to have a total mass emission rate of halogen atoms contained in organic compounds of 3,750 kg/yr or greater determined by the procedures presented in § 63.488(h).

Halogenated batch front-end process vent means a batch front-end process vent determined to have a mass emission rate of halogen atoms contained in organic compounds of 3,750 kg/yr or greater determined by the procedures presented in § 63.488(h).

Halogenated continuous front-end process vent means a continuous front-end process vent determined to have a mass emission rate of halogen atoms contained in organic compounds of 0.45 kg/hr or greater determined by the procedures presented in § 63.115(d)(2)(v).

High conversion latex means a latex where all monomers are reacted to at least 95 percent conversion.

Highest-HAP recipe for a product means the recipe of the product with the highest total mass of HAP charged to the reactor during the production of a single batch of product.

Hypalon™ means a chlorosulfonated polyethylene that is a synthetic rubber produced for uses such as wire and cable insulation, shoe soles and heels, automotive components, and building products.

In chloroprene service means the following:

(i) For process vents, each continuous front-end process vent, each batch front-end process vent, and each back-end process vent in a process at affected sources producing neoprene that, when uncontrolled, contains a concentration of greater than or equal to 1 ppmv undiluted chloroprene, and when combined, the sum of all these process vents within the process would emit uncontrolled, chloroprene emissions greater than or equal to 5 lb/yr (2.27 kg/yr). If information exists that suggests chloroprene could be present in a continuous front-end process vent, batch front-end process vent, or back-end process vent, then the process vent is considered to be ''in chloroprene service'' unless an analysis is performed as specified in § 63.509 to demonstrate that the process vent does not meet the definition of being ''in chloroprene service''. Examples of information that could suggest chloroprene could be present in a process vent, include calculations based on safety data sheets, material balances, process stoichiometry, or previous test results provided the results are still relevant to the current operating conditions.

(ii) For storage vessels, storage vessels of any capacity and vapor pressure in a process at affected sources producing neoprene storing a liquid that is at least 0.1 percent by weight of chloroprene. If knowledge exists that suggests chloroprene could be present in a storage vessel, then the storage vessel is considered to be ''in chloroprene service'' unless the procedures specified in § 63.509 are performed to demonstrate that the storage vessel does not meet the definition of being ''in chloroprene service''. The exemption for vessels ''storing and/or handling material that contains no organic HAP, or organic HAP as impurities only'' listed in the definition of ''storage vessel'' in this section does not apply for storage vessels that are in chloroprene service. Examples of information that could suggest chloroprene could be present in a storage vessel, include calculations based on safety data sheets, material balances, process stoichiometry, or previous test results provided the results are still relevant to the current operating conditions.

(iii) For wastewater streams, any wastewater stream in a process at affected sources producing neoprene that contains total annual average concentration of chloroprene greater than or equal to 10 parts per million by weight at any flow rate. If knowledge exists that suggests chloroprene could be present in a wastewater stream, then the wastewater stream is considered to be ''in chloroprene service'' unless sampling and analysis is performed as specified in § 63.509 to demonstrate that the wastewater stream does not meet the definition of being ''in chloroprene service''. Examples of information that could suggest chloroprene could be present in a wastewater stream, include calculations based on safety data sheets, material balances, process stoichiometry, or previous test results provided the results are still relevant to the current operating conditions.

Initial start-up means the first time a new or reconstructed affected source begins production of an elastomer product, or, for equipment added or changed as described in § 63.480(i), the first time the equipment is put into operation to produce an elastomer product. Initial start-up does not include operation solely for testing equipment. Initial start-up does not include subsequent start-ups of an affected source or portion thereof following shutdowns, or following changes in product for flexible operation units, or following recharging of equipment in batch operation.

Latex means a colloidal aqueous emulsion of elastomer. A latex may be further processed into finished products by direct use as a coating or as a foam, or it may be precipitated to separate the rubber particles, which are then used in dry state to prepare finished products.

Latex weight includes the weight of the polymer and the weight of the water solution.

Maintenance wastewater is defined in § 63.101, except that the term ''elastomer product process unit'' shall apply whenever the term ''chemical manufacturing process unit'' is used. Further, the generation of wastewater from the routine rinsing or washing of equipment in batch operation between batches is not maintenance wastewater, but is considered to be process wastewater, for the purposes of this subpart.

Maximum true vapor pressure is defined in § 63.111, except that the terms ''transfer'' and ''transferred'' shall not apply for the purposes of this subpart.

Multicomponent system means, as used in conjunction with batch front-end process vents, a stream whose liquid and/or vapor contains more than one compound.

Neoprene means a polymer of chloroprene (2-chloro-1,3-butadiene). The free radical emulsion process is generally used to produce neoprene, although other methods may be used.

New process unit means a process unit for which the construction or reconstruction commenced after June 12, 1995.

Nitrile butadiene latex means a polymer consisting primarily of unsaturated nitriles and dienes, usually acrylonitrile and 1,3-butadiene, that is sold as a latex.

Nitrile butadiene rubber means a polymer consisting primarily of unsaturated nitriles and dienes, usually acrylonitrile and 1,3-butadiene, not including nitrile butadiene latex.

On-site or on site means, with respect to records required to be maintained by this subpart or required by another subpart referenced by this subpart, that records are stored at a location within a major source which encompasses the affected source. On-site includes, but is not limited to, storage at the affected source or EPPU to which the records pertain, or storage in central files elsewhere at the major source.

Operating day means the period defined by the owner or operator in the Notification of Compliance Status required by § 63.506(e)(5). The operating day is the period for which daily average monitoring values and batch cycle daily average monitoring values are determined.

Organic hazardous air pollutant(s) (organic HAP) means one or more of the chemicals listed in table 5 to this subpart or any other chemical which:

(i) Is knowingly produced or introduced into the manufacturing process other than as an impurity; and

(ii) Is listed in table 2 to subpart F of this part.

Polybutadiene rubber by solution means a polymer of 1,3-butadiene produced using a solution process.

Polysulfide rubber means a polymer produced by reacting sodium polysulfide and chloroethyl formal. Polysulfide rubber may be produced as latexes or solid product.

Primary product is defined in and determined by the procedures specified in § 63.480(f).

Process section means the equipment designed to accomplish a general but well-defined task in polymers production. Process sections include raw materials preparation, polymerization reaction, and material recovery. A process section may be dedicated to a single EPPU or may be common to more than one EPPU.

Process unit means a collection of equipment assembled and connected by hard-piping or duct work, used to process raw materials and to manufacture a product.

Process vent means a gaseous emission stream from a unit operation that is discharged to the atmosphere either directly or after passing through one or more control, recovery, or recapture devices. Unit operations that may have process vents are condensers, distillation units, reactors, or other unit operations within the EPPU. Process vents exclude pressure releases, gaseous streams routed to a fuel gas system(s), and leaks from equipment regulated under § 63.502. A gaseous emission stream is no longer considered to be a process vent after the stream has been controlled and monitored in accordance with the applicable provisions of this subpart.

Product means a polymer produced using the same monomers, and varying in additives (*e.g.,* initiators, terminators, etc.); catalysts; or in the relative proportions of monomers, that is manufactured by a process unit. With respect to polymers, more than one recipe may be used to produce the same product, and there can be more than one grade of a product. As an example, styrene butadiene latex and butyl rubber each represent a different product. Product also means a chemical that is not a polymer, is manufactured by a process unit. By-products, isolated intermediates, impurities, wastes, and trace contaminants are not considered products.

Recipe means a specific composition, from among the range of possible compositions that may occur within a product, as defined in this section. A recipe is determined by the proportions of monomers and, if present, other reactants and additives that are used to make the recipe. For example, styrene butadiene latex without additives; styrene butadiene latex with an additive; and styrene butadiene latex with different proportions of styrene to butadiene are all different recipes of the same product, styrene butadiene latex.

Reconstruction means the replacement of components of an affected source or of a previously unaffected stationary source that becomes an affected source as a result of the replacement, to such an extent that:

(i) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source; and

(ii) It is technologically and economically feasible for the reconstructed source to meet the provisions of this subpart.

Recovery device means:

(i) An individual unit of equipment capable of and normally used for the purpose of recovering chemicals for:

(A) Use;

(B) Reuse;

(C) Fuel value (*i.e.,* net heating value); or

(D) For sale for use, reuse, or fuel value (*i.e.,* net heating value).

(ii) Examples of equipment that may be recovery devices include absorbers, carbon adsorbers, condensers, oil-water separators or organic-water separators, or organic removal devices such as decanters, strippers, or thin film evaporation units. For the purposes of the monitoring, recordkeeping, or reporting requirements of this subpart, recapture devices are considered recovery devices.

Recovery operations equipment means the equipment used to separate the components of process streams. Recovery operations equipment includes distillation units, condensers, etc. Equipment used for wastewater treatment and recovery or recapture devices used as control devices shall not be considered recovery operations equipment.

Residual is defined in § 63.111, except that when the definition in § 63.111 uses the term ''table 9 compounds,'' the term ''organic HAP listed in table 5 to subpart U of this part'' shall apply, for the purposes of this subpart.

Resin, for the purposes of this subpart, means a polymer with the following characteristics:

(i) The polymer is a block polymer;

(ii) The manufactured polymer does not require vulcanization to make useful products;

(iii) The polymer production process is operated to achieve at least 99 percent monomer conversion; and

(iv) The polymer process unit does not recycle unreacted monomer back to the process.

Shutdown means for purposes including, but not limited to, periodic maintenance, replacement of equipment, or repair, the cessation of operation of an affected source, an EPPU within an affected source, a waste management unit or unit operation within an affected source, or equipment required or used to comply with this subpart, or the emptying or degassing of a storage vessel. For purposes of the wastewater provisions of § 63.501, shutdown does not include the routine rinsing or washing of equipment in batch operation between batches. For purposes of the batch front-end process vent provisions in §§ 63.486 through 63.492, the cessation of equipment in batch operation is not a shutdown, unless the equipment undergoes maintenance, is replaced, or is repaired.

Solution process means a process where both the monomers and the resulting polymers are dissolved in an organic solvent.

Start-up means the setting into operation of an affected source, an EPPU within the affected source, a waste management unit or unit operation within an affected source, or equipment required or used to comply with this subpart, or a storage vessel after emptying and degassing. For both continuous and batch front-end processes, start-up includes initial start-up and operation solely for testing equipment. For both continuous and batch front-end processes, start-up does not include the recharging of equipment in batch operation. For continuous front-end processes, start-up includes transitional conditions due to changes in product for flexible operation units. For batch front-end processes, start-up does not include transitional conditions due to changes in product for flexible operation units.

Steady-state conditions means that all variables (temperatures, pressures, volumes, flow rates, etc.) in a process do not vary significantly with time; minor fluctuations about constant mean values may occur.

Storage vessel means a tank or other vessel that is used to store liquids that contain one or more organic HAP. Storage vessels do not include:

(i) Vessels permanently attached to motor vehicles such as trucks, railcars, barges, or ships;

(ii) Except for storage vessels in chloroprene service, vessels with capacities smaller than 38 cubic meters;

(iii) Except for storage vessels in chloroprene service, vessels and equipment storing and/or handling material that contains no organic HAP, or organic HAP as impurities only;

(iv) Surge control vessels and bottoms receivers; and

(v) Wastewater storage tanks.

Stripper means a unit operation where stripping occurs.

Stripping means the removal of organic compounds from a raw elastomer product. In the production of an elastomer, stripping is a discrete step that occurs after the reactors and before the dryers (other than those dryers with a primary purpose of devolitalization) and other finishing operations. Examples of types of stripping include steam stripping, direct volatilization, chemical stripping, and other methods of devolatilization. For the purposes of this subpart, devolatilization that occurs in dryers (other than those dryers with a primary purpose of devolatilization), extruders, and other finishing operations is not stripping.

Styrene butadiene latex means a polymer consisting primarily of styrene and butadiene monomer units produced using an emulsion process and sold as a latex.

Styrene butadiene rubber by emulsion means a polymer consisting primarily of styrene and butadiene monomer units produced using an emulsion process. Styrene butadiene rubber by emulsion does not include styrene butadiene latex.

Styrene butadiene rubber by solution means a polymer that consists primarily of styrene and butadiene monomer units and is produced using a solution process.

Supplemental combustion air means the air that is added to a vent stream after the vent stream leaves the unit operation. Air that is part of the vent stream as a result of the nature of the unit operation is not considered supplemental combustion air. Air required to operate combustion device burner(s) is not considered supplemental combustion air. Air required to ensure the proper operation of catalytic oxidizers, to include the intermittent addition of air upstream of the catalyst bed to maintain a minimum threshold flow rate through the catalyst bed or to avoid excessive temperatures in the catalyst bed, is not considered to be supplemental combustion air.

Suspension process means a polymerization process where the monomer(s) is in a state of suspension, with the help of suspending agents in a medium other than water (typically an organic solvent). The resulting polymers are not soluble in the reactor medium.

Total organic compounds (TOC) means those compounds, excluding methane and ethane, measured according to the procedures of Method 18 or Method 25A of appendices A–6 and A–7 to 40 CFR part 60, respectively, or ASTM D6420–18 (incorporated by reference, see § 63.14) as specified in this subpart.

Total resource effectiveness index value or TRE index value means a measure of the supplemental total resource requirement per unit reduction of organic HAP associated with a continuous front-end process vent stream, based on vent stream flow rate, emission rate of organic HAP, net heating value, and corrosion properties (whether or not the continuous front-end process vent stream contains halogenated compounds), as quantified by the equations given under § 63.115, with the exceptions noted in § 63.485.

Vent stream, as used in reference to batch front-end process vents, continuous front-end process vents, and aggregate batch vent streams, means the emissions from one or more process vents.

Waste management unit is defined in § 63.111, except that where the definition in § 63.111 uses the term ''chemical manufacturing process unit,'' the term ''EPPU'' shall apply for the purposes of this subpart.

Wastewater means water that:

(i) Contains either:

(A) An annual average concentration of organic HAP listed in table 5 to this subpart of at least 5 parts per million by weight and has an annual average flow rate of 0.02 liter per minute or greater; or

(B) An annual average concentration of organic HAP listed in table 5 to this subpart of at least 10,000 parts per million by weight at any flow rate; and

(ii) Is discarded from an EPPU that is part of an affected source. Wastewater is process wastewater or maintenance wastewater.

Wastewater stream means a stream that contains wastewater as defined in this section.

■ 123. Amend § 63.483 by revising paragraph (a) introductory text and adding paragraph (e) to read as follows:

§ 63.483 Emission standards.

(a) At all times, each owner or operator must operate and maintain any affected source subject to the requirements of this subpart, 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 or operator to make any further efforts to reduce emissions if levels required by this 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. Except as allowed under paragraphs (b) through (d) of this section, the owner or operator of an existing or new affected source shall comply with the provisions in paragraphs (a)(1) through (a)(9) of this section.

* * * * *

(e) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), owners and operators of sources as defined in § 63.480 shall comply with the requirements of this subpart at all times, except during periods of nonoperation of the source (or specific portion thereof) resulting in cessation of the emissions to which this subpart applies.

■ 124. Amend § 63.484 by revising paragraphs (a) and (i)(2), and adding paragraphs (t) and (u) to read as follows:

§ 63.484 Storage vessel provisions.

(a) This section applies to each storage vessel that is assigned to an affected source, as determined by § 63.480(g). Except for those storage vessels exempted by paragraph (b) of this section, the owner or operator of affected sources shall comply with the requirements of §§ 63.119 through 63.123 and 63.148, with the differences noted in paragraphs (c) through (u) of this section, for the purposes of this subpart.

* * * * *

(i) * * *

(2) The performance test is submitted as part of the Notification of Compliance Status required by § 63.506(e)(5). If the performance test report is submitted electronically through the EPA's CEDRI in accordance with § 63.152(h), the process unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the notification of compliance status report in lieu of the performance test results. The performance test results must be submitted to CEDRI by the date the notification of compliance status report is submitted.

* * * * *

(t) Owners and operators of affected sources must make the substitutions as specified in paragraphs (t)(1) through (4) of this section:

(1) Substitute ''For each affected source as described in § 63.480'' for each occurrence of the phrase ''For each source as defined in § 63.101''.

(2) Substitute ''beginning no later than the compliance dates specified in § 63.481(n)'' for each occurrence of the phrase ''beginning no later than the compliance dates specified in § 63.100(k)(10)''.

(3) Substitute ''owners and operators of affected sources as described in § 63.480'' for each occurrence of the phrase ''owners and operators of sources as defined in § 63.101''.

(4) Substitute ''§ 63.508'' for each occurrence of ''§ 63.108''.

(u) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(o), if the storage vessel (of any capacity and vapor pressure) stores liquid containing chloroprene such that the storage vessel is considered to be in chloroprene service, as defined in § 63.482, then the owner or operator must comply with the requirements of paragraphs (u)(1) through (3) of this section in addition to all other applicable requirements specified in § 63.483 and elsewhere in this section.

(1) Reduce emissions of chloroprene by venting emissions through a closed vent system to a non-flare control device that reduces chloroprene by greater than or equal to 98 percent by weight, or to a concentration less than 1 ppmv for each storage vessel vent. If a combustion device is used, the chloroprene concentration of 1 ppmv must be corrected to 3 percent oxygen.

(2) To demonstrate compliance with the emission limits specified in paragraph (u)(1) of this section for storage vessels in chloroprene service, owners and operators must meet the requirements specified in § 63.510.

(3) Owners and operators must keep the records specified in paragraphs (u)(3)(i) and (u)(3)(ii) of this section in addition to those records specified elsewhere in this section.

(i) For storage vessels in chloroprene service, records of the concentration of chloroprene of the fluid stored in each storage vessel.

(ii) The owner or operator must keep records of all periods during which operating values are outside of the applicable operating limits specified in § 63.510(b)(4) through (6) when regulated material is being routed to the non-flare control device. The record must specify the operating parameter, the applicable limit, and the highest (for maximum operating limits) or lowest (for minimum operating limits) value recorded during the period.

■ 125. Amend § 63.485 by:

■ a. Revising paragraphs (a), (l), (o) and (p)(3);

■ b. Adding paragraph (p)(5);

■ c. Revising paragraphs (q)(1) introductory text, (q)(1)(ii), and (q)(2);

■ d. Adding paragraph (q)(3);

■ e. Revising paragraphs (s) introductory text, (s)(5), and (t); and

■ f. Adding paragraphs (x), (y) and (z).

The revisions and additions read as follows:

§ 63.485 Continuous front-end process vent provisions.

(a) For each continuous front-end process vent located at an affected source, the owner or operator shall comply with the requirements of §§ 63.113 through 63.118, except as provided for in paragraphs (b) through (z) of this section. The owner or operator of continuous front-end process vents that are combined with one or more batch front-end process vents shall comply with paragraph (o) or (p) of this section.

* * * * *

(l) When reports of process changes are required under § 63.118(g), (h), (i), or (j), paragraphs (l)(1) through (4) and (l)(6) of this section shall apply for the purposes of this subpart. In addition, for the purposes of this subpart paragraph (l)(5) of this section applies, and § 63.118(k) does not apply to owners or operators of affected sources.

* * * * *

(2) Except as specified in paragraph (l)(6) of this section, whenever a process change, as defined in § 63.115(e), is made that causes a Group 2 continuous front-end process vent with a TRE greater than 4.0 to become a Group 2 continuous front-end process vent with a TRE less than 4.0, the owner or operator shall submit a report within 180 days after the process change is made or with the next Periodic Report, whichever is later. A description of the process change shall be submitted with the report of the process change, and the owner or operator shall comply with the provisions in § 63.113(d) by the dates specified in § 63.481.

(3) Except as specified in paragraph (l)(6) of this section, whenever a process change, as defined in § 63.115(e), is made that causes a Group 2 continuous front-end process vent with a flow rate less than 0.005 standard cubic meter per minute (scmm) to become a Group 2 continuous front-end process vent with a flow rate of 0.005 scmm or greater and a TRE index value less than or equal to 4.0, the owner or operator shall submit a report within 180 days after the process change is made or with the next Periodic Report, whichever is later. A description of the process change shall be submitted with the report of the process change, and the owner or operator shall comply with the provisions in § 63.113(d) by the dates specified in § 63.481.

(4) Except as specified in paragraph (l)(6) of this section, whenever a process change, as defined in § 63.115(e), is made that causes a Group 2 continuous front-end process vent with an organic HAP concentration less than 50 parts per million by volume (ppmv) to become a Group 2 continuous front-end process vent with an organic HAP concentration of 50 ppmv or greater and a TRE index value less than or equal to 4.0, the owner or operator shall submit a report within 180 days after the process change is made or with the next Periodic Report, whichever is later. A description of the process change shall be submitted with the report of the process change, and the owner or operator shall comply with the provisions in § 63.113(d) by the dates specified in § 63.481.

(5) * * *

(iv) Except as specified in paragraph (l)(6) of this section, the TRE index value is recalculated according to § 63.115(e) and the recalculated value is greater than 4.0.

(6) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraphs (l)(2), (3), (4), and (l)(5)(iv) of this section no longer apply.

* * * * *

(o) If a batch front-end process vent or aggregate batch vent stream is combined with a continuous front-end process vent, the owner or operator of the affected source containing the combined vent stream shall comply with paragraph (o)(1); with paragraph (o)(2) and (o)(6) with paragraph (o)(3) or (o)(4); or with paragraph (o)(5) of this section, as appropriate.

* * * * *

(2) Except as specified in paragraph (o)(6) of this section, if a batch front-end process vent or aggregate batch vent stream is combined with a continuous front-end process vent prior to the combined vent stream being routed to a recovery device, the TRE index value for the combined vent stream shall be calculated at the exit of the last recovery device. The TRE shall be calculated during periods when one or more batch emission episodes are occurring that result in the highest organic HAP emission rate (in the combined vent stream that is being routed to the recovery device) that is achievable during the 6-month period that begins 3 months before and ends 3 months after the TRE calculation, without causing any of the situations described in paragraphs (o)(2)(i) through (o)(2)(iii) of this section to occur.

* * * * *

(3) Except as specified in paragraph (o)(6) of this section, if the combined vent stream described in paragraph (o)(2) of this section meets the requirements in paragraphs (o)(3)(i), (o)(3)(ii), and (o)(3)(iii) of this section, the combined vent stream shall be subject to the requirements for Group 1 process vents in §§ 63.113 through 63.118, except as otherwise provided in this section, as applicable. Performance tests for the combined vent stream shall be conducted at maximum

representative operating conditions, as described in paragraph (o)(1) of this section.

* * * * *

(4) Except as specified in paragraph (o)(6) of this section, if the combined vent stream described in paragraph (o)(2) of this section meets the requirements in paragraph (o)(4)(i), (ii), or (iii) of this section, the combined vent stream shall be subject to the requirements for Group 2 process vents in §§ 63.113 through 63.118, except as otherwise provided in this section, as applicable.

* * * * *

(6) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraphs (o)(2) through (4) of this section no longer apply.

(p) * * *

(3) Except as specified in paragraph (p)(5) of this section, the efficiency of the final recovery device (determined according to paragraph (p)(4) of this section) shall be applied to the total organic HAP or TOC concentration measured at the sampling site described in paragraph (p)(2) of this section to determine the exit concentration. This exit concentration of total organic HAP or TOC shall then be used to perform the calculations outlined in § 63.115(d)(2)(iii) and § 63.115(d)(2)(iv), for the combined vent stream exiting the final recovery device.

* * * * *

(5) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), the last sentence in paragraph (p)(3) of this section: ''This exit concentration of total organic HAP or TOC shall then be used to perform the calculations outlined in § 63.115(d)(2)(iii) and § 63.115(d)(2)(iv), for the combined vent stream exiting the final recovery device.'' no longer applies.

(q) * * *

(1) Group 1 halogenated continuous front-end process vents at existing affected sources producing butyl rubber or ethylene propylene rubber using a solution process are exempt from the provisions of § 63.113(a)(1)(ii) and § 63.113(c) if the conditions in paragraphs (q)(1)(i) and (ii) of this section are met, and shall comply with the requirements in paragraphs (q)(1)(iii) through (vi) of this section. Group 1 halogenated continuous front-end process vents at new affected sources producing butyl rubber or ethylene propylene rubber using a solution process are not exempt from § 63.113(a)(1)(ii) and § 63.113(c).

* * * * *

(ii) Except as specified in paragraph (q)(3) of this section, if the requirements of § 63.113(a)(2); § 63.113(a)(3); § 63.113(b) and the associated testing requirements in § 63.116; or § 63.11(b) and § 63.504(c) are met.

* * * * *

(2) Except as specified in paragraph (q)(3) of this section, Group 1 halogenated continuous front-end process vents at new and existing affected sources producing an elastomer using a gas-phased reaction process, provided that the requirements of § 63.113(a)(2); § 63.113(a)(3); § 63.113(b) and the associated testing requirements in § 63.116; or § 63.11(b) and § 63.504(c) are met.

(3) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraphs (q)(1)(ii) and (q)(2) of this section no longer apply. Instead, the requirements of § 63.113(a)(2); §§ 63.113(b) and the associated testing requirements in § 63.116; or § 63.508 must be met.

* * * * *

(s) *Internal combustion engines.* In addition to the three options for the control of a Group 1 continuous front-end process vent listed in § 63.113(a)(1) through (3), except as specified in § 63.113(a)(4) of subpart G of this part, an owner or operator will be permitted to route emissions of organic HAP to an internal combustion engine, provided the conditions listed in paragraphs (s)(1) through (s)(5) of this section are met.

* * * * *

(5) The owner or operator shall include in the Periodic Report a report of all times that the internal combustion engine was not operating while emissions were being routed to it. Include the start date and time and end date and time for all such periods.

* * * * *

(t) When the provisions of § 63.116(c)(3) and (4) specify that Method 18 of appendix A–6 to 40 CFR part 60 must be used, Method 18 or Method 25A of appendices A–6 and A–7 to 40 CFR part 60, respectively, may be used for the purposes of this subpart. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method. The use of Method 25A must conform with the requirements in paragraphs (t)(1) and (2) of this section.

(1) The organic HAP used as the calibration gas for Method 25A of appendix A–7 to 40 CFR part 60 must be the single organic HAP representing the largest percent by volume of the emissions.

* * * * *

(x) Owners and operators of affected sources must make the substitutions as specified in paragraphs (x)(1) through (4) of this section:

(1) Substitute ''For each affected source as described in § 63.480'' for each occurrence of the phrase ''For each source as defined in § 63.101''.

(2) Substitute ''beginning no later than the compliance dates specified in § 63.481(n)'' for each occurrence of the phrase ''beginning no later than the compliance dates specified in § 63.100(k)(10)''.

(3) Substitute ''owners and operators of affected sources as described in § 63.480'' for each occurrence of the phrase ''owners and operators of sources as defined in § 63.101''.

(4) Substitute ''§ 63.508'' for each occurrence of ''§ 63.108''.

(y) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(o), if the Group 1 or Group 2 continuous front-end process vent contains chloroprene such that it is considered to be in chloroprene service, as defined in § 63.482, then the owner or operator must comply with the requirements of paragraphs (y)(1) through (4) of this section in addition to all other applicable requirements specified in § 63.483 and elsewhere in this section.

(1) Reduce emissions of chloroprene by venting emissions through a closed vent system to a non-flare control device that reduces chloroprene by greater than or equal to 98 percent by weight, or to a concentration less than 1 ppmv for each process vent or to less than 5 pounds per year for all combined process vents within the process. If a combustion device is used, the chloroprene concentration of 1 ppmv must be corrected to 3 percent oxygen.

(2) To demonstrate compliance with the emission limits specified in paragraph (y)(1) of this section for continuous front-end process vents in chloroprene service, owners and operators must meet the requirements specified in § 63.510.

(3) Owners and operators must keep the records specified in paragraphs (y)(3)(i) and (y)(3)(ii) of this section in addition to those records specified elsewhere in this section.

(i) For process vents, include all uncontrolled, undiluted chloroprene concentration measurements, and the calculations used to determine the total uncontrolled chloroprene mass emission rate for the sum of all vent gas streams.

(ii) The owner or operator must keep records of all periods during which operating values are outside of the applicable operating limits specified in § 63.510(b)(4) through (6) when regulated material is being routed to the non-flare control device. The record must specify the operating parameter, the applicable limit, and the highest (for maximum operating limits) or lowest (for minimum operating limits) value recorded during the period.

(4) The Periodic Report must include the records for the periods specified in paragraph (y)(3)(ii) of this section. Indicate the start date, start time and duration in hours for each period.

(z) For continuous front-end process vents that are in chloroprene service and subject to the requirements of § 63.510, the requirements in 40 CFR 63.113(k)(4) do not apply. Instead, in addition to complying with the requirements in paragraphs 40 CFR 63.113(k)(1) through (3), for continuous front-end process vents that are in chloroprene service and subject to the requirements of § 63.510 that are designated as maintenance vents, owners and operators may not release more than 1.0 tons of chloroprene from all maintenance vents combined (*i.e.,* including maintenance vents subject to this paragraph (z), § 63.487(i)(4), or § 63.494(a)(7)(iii)) per any consecutive 12-month period. The owner or operator must keep monthly records of the quantity in tons of chloroprene released from each maintenance vent and include a description of the method used to estimate this quantity.

■ 126. Amend § 63.487 by:

■ a. Revising and republishing paragraphs (a) and (b);

■ b. Revising paragraphs (c) introductory text, (c)(1) and (e)(1)(iii);

■ c. Adding paragraph (e)(1)(iv);

■ d. Revising paragraphs (f) introductory text and (g) introductory text; and

■ e. Adding paragraphs (i) and (j).

The revisions, additions and republications read as follows:

§ 63.487 Batch front-end process vents—reference control technology.

(a) *Batch front-end process vents.* Except as specified in paragraph (j) of this section, the owner or operator of an affected source with a Group 1 batch front-end process vent, as determined using the procedures in § 63.488, shall comply with the requirements of either paragraph (a)(1) or (a)(2) of this section, and paragraph (a)(3) of this section. Compliance may be based on either organic HAP or TOC.

(1) For each batch front-end process vent, reduce organic HAP emissions using a flare.

(i) Except as specified in paragraph (a)(1)(iii) of this section, the owner or operator of the affected sources shall comply with the requirements of § 63.504(c) for the flare.

(ii) Halogenated batch front-end process vents, as defined in § 63.482, shall not be vented to a flare.

(iii) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (a)(1)(i) of this section no longer applies and instead the owner or operator of the affected sources must comply with § 63.508 for the flare.

(2) For each batch front-end process vent, reduce organic HAP emissions for the batch cycle by 90 weight percent using a control device. Owners or operators may achieve compliance with this paragraph through the control of selected batch emission episodes or the control of portions of selected batch emission episodes. Documentation demonstrating how the 90 weight percent emission reduction is achieved is required by § 63.490(c)(2).

(3) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), for each batch front-end process vent that contains chlorine, HCl, or any other chlorinated compound, reduce emissions of dioxins and furans (toxic equivalency basis) to a concentration of 0.054 nanograms per standard cubic meter on a dry basis corrected to 3 percent oxygen.

(b) *Aggregate batch vent streams.* Except as specified in paragraph (j) of this section the owner or operator of an aggregate batch vent stream that contains one or more Group 1 batch front-end process vents shall comply with the requirements of either paragraph (b)(1) or (b)(2) of this section, and paragraph (b)(3) of this section. Compliance may be based on either organic HAP or TOC.

(1) For each aggregate batch vent stream, reduce organic HAP emissions using a flare.

(i) Except as specified in paragraph (b)(1)(iii) of this section, the owner or operator of the affected source shall comply with the requirements of § 63.504(c) for the flare.

(ii) Halogenated aggregate batch vent streams, as defined in § 63.482, shall not be vented to a flare.

(iii) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (b)(1)(i) of this section no longer applies and instead the owner or operator of the affected source must comply with § 63.508 for the flare.

(2) For each aggregate batch vent stream, reduce organic HAP emissions by 90 weight percent or to a concentration of 20 ppmv, on a continuous basis using a control device. For purposes of complying with the 20 ppmv outlet concentration standard, the outlet concentration shall be calculated on a dry basis. When a combustion device is used for purposes of complying with the 20 ppmv outlet concentration standard, the concentration shall be corrected to 3 percent oxygen if supplemental combustion air is used to combust the emissions. If supplemental combustion air is not used, a correction to 3 percent oxygen is not required.

(3) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), for each aggregate batch vent stream that contains chlorine, HCl, or any other chlorinated compound, reduce emissions of dioxins and furans (toxic equivalency basis) to a concentration of 0.054 nanograms per standard cubic meter on a dry basis corrected to 3 percent oxygen

(c) *Halogenated emissions.* Halogenated Group 1 batch front-end process vents, halogenated aggregate batch vent streams, and halogenated continuous front-end process vents that are combusted as part of complying with paragraph (a)(2), (a)(3), (b)(2), or (b)(3) of this section, shall be controlled according to either paragraph (c)(1) or (c)(2) of this section.

(1) If a combustion device is used to comply with paragraph (a)(2), (a)(3), (b)(2), or (b)(3) of this section for a halogenated batch front-end process vent or halogenated aggregate batch vent stream, the emissions exiting the combustion device shall be ducted to a halogen reduction device that reduces overall emissions of hydrogen halides and halogens by at least 99 percent before discharge to the atmosphere.

* * * * *

(e) * * *

(1) * * *

(iii) Except as specified in paragraph (e)(1)(iv) of this section, the batch front-end process vent or aggregate batch vent stream is combined with a continuous front-end process vent stream prior to being routed to a recovery device. In this paragraph (e)(1)(iii), the definition of recovery device as it relates to continuous front-end process vents shall be used. Furthermore, the combined vent stream discussed in this paragraph (e)(1)(iii) shall be subject to § 63.485(o)(2).

(iv) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (e)(1)(iii) of this section no longer applies.

* * * * *

(f) *Group 2 batch front-end process vents with annual emissions greater than or equal to the level specified in § 63.488(d).* Except as specified in paragraph (j) of this section, the owner or operator of a Group 2 batch front-end process vent with annual emissions greater than or equal to the level specified in § 63.488(d) shall comply with the provisions of paragraph (f)(1), (f)(2), or (h) of this section.

* * * * *

(g) *Group 2 batch front-end process vents with annual emissions less than the level specified in § 63.488(d).* Except as specified in paragraph (j) of this section, the owner or operator of a Group 2 batch front-end process vent with annual organic HAP emissions less than the level specified in § 63.488(d), shall comply with paragraph (g)(1), (g)(2), (g)(3), or (g)(4) of this section.

* * * * *

(i) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), an owner or operator may designate a batch front-end 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 must comply with the applicable requirements in paragraphs (i)(1) through (i)(4) of this section for each maintenance vent. Any vent designated as a maintenance vent is only subject to the maintenance vent provisions in this paragraph (i) and the associated recordkeeping and reporting requirements in § 63.491(h) and § 63.492(g), respectively. The owner or operator does not need to designate a maintenance vent as a Group 1 or Group 2 batch front-end process vent nor identify maintenance vents in a Notification of Compliance Status report.

(1) Prior to venting to the atmosphere, remove process liquids from the equipment as much as practical and depressurize the equipment to either: A flare meeting the requirements of § 63.508, as applicable, or using any combination of a non-flare combustion, recovery, and/or recapture device meeting the requirements in paragraph (a)(2) of this section until one of the following conditions, as applicable, is met.

(i) The concentration of the vapor in the equipment served by the maintenance vent is less than 10 percent of its lower explosive limit (LEL) and has an outlet concentration less than or equal to 20 ppmv hydrogen halide and halogen HAP.

(ii) If there is no ability to measure the concentration 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 pounds per square inch gauge (psig) or less. Upon opening the maintenance vent, active purging of the equipment cannot be used until the concentration of the vapors in the maintenance vent (or inside the equipment if the maintenance is a hatch or similar type of opening) is less than 10 percent of its LEL.

(iii) The equipment served by the maintenance vent contains less than 50 pounds of total volatile organic compounds (VOC).

(iv) If, after applying best practices to isolate and purge equipment served by a maintenance vent, none of the applicable criterion in paragraphs (i)(1)(i) through (i)(1)(iii) of this section can be met prior to installing or removing a blind flange or similar equipment blind, then the pressure in the equipment served by the maintenance vent must be reduced to 2 psig or less before installing or removing the equipment blind. During installation or removal of the equipment blind, active purging of the equipment may be used provided the equipment pressure at the location where purge gas is introduced remains at 2 psig or less.

(2) Except for maintenance vents complying with the alternative in paragraph (i)(1)(iii) of this section, the owner or operator must determine the concentration 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 (i)(1)(iii) of this section, the owner or operator must 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.

(4) In addition to complying with the requirements in paragraphs (i)(1) through (i)(3) of this section, for batch front-end process vents that are in chloroprene service and subject to the requirements of § 63.510 that are designated as maintenance vents, owners and operators may not release more than 1.0 tons of chloroprene from all maintenance vents combined (*i.e.,* including maintenance vents subject to this paragraph (i)(4), § 63.485(z), or § 63.494(a)(7)(iii)) per any consecutive 12-month period. The owner or operator must keep monthly records of the quantity in tons of chloroprene released from each maintenance vent and include a description of the method used to estimate this quantity.

(j) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(o), if the Group 1 or Group 2 batch front-end process vent contains chloroprene such that it is considered to be in chloroprene service, as defined in § 63.482, then the owner or operator must comply with the requirements of paragraphs (j)(1) through (j)(4) of this section in addition to all other applicable requirements specified in § 63.483 and elsewhere in this section.

(1) Reduce emissions of chloroprene by venting emissions through a closed vent system to a non-flare control device that reduces chloroprene by greater than or equal to 98 percent by weight, or to a concentration less than 1 ppmv for each process vent or to less than 5 pounds per year for all combined process vents within the process. If a combustion device is used, the chloroprene concentration of 1 ppmv must be corrected to 3 percent oxygen.

(2) To demonstrate compliance with the emission limits specified in paragraph (j)(1) of this section for batch front-end process vents in chloroprene service, owners and operators must meet the requirements specified in § 63.510.

(3) Owners and operators must keep the records specified in paragraphs (j)(3)(i) and (j)(3)(ii) of this section in addition to those records specified elsewhere in this section.

(i) For process vents, include all uncontrolled, undiluted chloroprene concentration measurements, and the calculations used to determine the total uncontrolled chloroprene mass emission rate for the sum of all vent gas streams.

(ii) The owner or operator must keep records of all periods during which operating values are outside of the applicable operating limits specified in § 63.510(b)(4) through (6) when regulated material is being routed to the non-flare control device. The record must specify the operating parameter, the applicable limit, and the highest (for maximum operating limits) or lowest (for minimum operating limits) value recorded during the period.

(4) The Periodic Report must include the records of periods specified in paragraph (j)(3)(ii) of this section. Indicate the start date, start time and duration in hours for each period.

■ 127. Amend § 63.488 by:
■ a. Revising paragraphs (b)(5)(iii), (d), and (e) introductory text,
■ b. Adding paragraph (e)(4); and
■ c. Revising paragraphs (f) and (g).

The revisions and addition read as follows:

§ 63.488 Methods and procedures for batch front-end process vent group determination.

* * * * *

(b) * * *

(5) * * *

(iii) Method 18 or Method 25A of appendices A–6 and A–7 to 40 CFR part 60, respectively, must be used to determine the concentration of TOC or organic HAP, as appropriate. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method. The use of Method 25A must conform with the requirements in paragraphs (b)(5)(iii)(A) and (B) of this section.

(A) The organic HAP used as the calibration gas for Method 25A of appendix A–7 to 40 CFR part 60 must be the single organic HAP representing the largest percent by volume of the emissions.

* * * * *

(d) *Minimum emission level exemption.* (1) Except as specified in paragraph (d)(2) of this section, a batch front-end process vent with annual emissions of TOC or organic HAP less than 11,800 kg/yr is considered a Group 2 batch front-end process vent and the owner or operator of that batch front-end process vent shall comply with the requirements in § 63.487(f) or (g). Annual emissions of TOC or organic HAP are determined at the exit of the batch unit operation, as described in paragraph (a)(2) of this section, and are determined as specified in paragraph (b) of this section. The owner or operator of that batch front-end process vent is not required to comply with the provisions in paragraphs (e) through (g) of this section.

(2) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (d)(1) of this section no longer applies and instead the collection of all batch front-end process vents with combined total annual emissions of TOC or organic HAP less than 4,536 kg/yr (10,000 lb/yr) are considered Group 2 batch front-end process vents. Annual emissions of TOC or organic HAP are determined at the exit of each batch unit operation, as described in paragraph (a)(2) of this section, and are determined as specified in paragraph (b) of this section.

(e) *Determination of average batch vent flow rate and annual average batch vent flow rate.* Except as specified in paragraph (e)(4) of this section, the owner or operator shall determine the average batch vent flow rate for each batch emission episode in accordance with one of the procedures provided in paragraphs (e)(1) through (e)(2) of this section. The annual average batch vent flow rate for a batch front-end process vent shall be calculated as specified in paragraph (e)(3) of this section.

* * * * *

(4) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (e) of this section no longer applies.

(f) *Determination of cutoff flow rate.* (1) Except as specified in paragraph (f)(2) of this section, for each batch front-end process vent, the owner or operator shall calculate the cutoff flow rate using Equation 15.

Equation 15 to Paragraph (f)

$$CFR = (0.00437)(AE) - 51.6 \quad \text{[Eq. 15]}$$

Where:

CFR = Cutoff flow rate, scmm.
AE = Annual TOC or organic HAP emissions, as determined in paragraph (b)(8) of this section, kg/yr.

(2) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (f) of this section no longer applies.

(g) *Group 1/Group 2 status determination.* Except as specified in paragraph (g)(3) of this section, the owner or operator shall compare the cutoff flow rate, calculated in accordance with paragraph (f) of this section, with the annual average batch vent flow rate, determined in accordance with paragraph (e)(3) of this section. The group determination status for each batch front-end process vent shall be made using the criteria specified in paragraphs (g)(1) and (g)(2) of this section.

(1) If the cutoff flow rate is greater than or equal to the annual average batch vent flow rate of the stream, the batch front-end process vent is classified as a Group 1 batch front-end process vent.

(2) If the cutoff flow rate is less than the annual average batch vent flow rate of the stream, the batch front-end process vent is classified as a Group 2 batch front-end process vent.

(3) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (g) of this section no longer applies.

* * * * *

■ 128. Amend § 63.489 by:
■ a. Revising paragraphs (a) introductory text, (b) introductory text, (b)(2), and (b)(7);
■ b. Adding paragraphs (b)(9), (10) and (11);
■ c. Revising paragraph (d) introductory text and adding paragraph (d)(3); and
■ d. Revising paragraph (e)(1)(i), and adding paragraph (e)(1)(iii).

The revisions and additions read as follows:

§ 63.489 Batch front-end process vents—monitoring equipment.

(a) *General requirements.* Each owner or operator of a batch front-end process vent or aggregate batch vent stream that uses a control device to comply with the requirements in § 63.487(a)(2) or (3) or § 63.487(b)(2) or (3) shall install the monitoring equipment specified in paragraph (b) of this section. All monitoring equipment shall be installed, calibrated, maintained, and operated according to the manufacturer's specifications or other written procedures that provide adequate assurance that the equipment would reasonably be expected to monitor accurately.

* * * * *

(b) *Batch front-end process vent and aggregate batch vent stream monitoring equipment.* The monitoring equipment specified in paragraphs (b)(1) through (b)(11) of this section shall be installed as specified in paragraph (a) of this section. The parameters to be monitored are specified in Table 6 of this subpart.

* * * * *

(2) Where a flare is used, except as specified in paragraph (b)(9) of this section, a device (including, but not limited to, a thermocouple, ultra-violet beam sensor, or infrared sensor) capable of continuously detecting the presence of a pilot flame is required.

* * * * *

(7) Except as specified in paragraph (b)(10) of this section, where a carbon adsorber is used, an integrating regeneration steam flow, nitrogen flow, or pressure monitoring device having an accuracy of ±10 percent of the flow rate, level, or pressure, or better, capable of recording the total regeneration steam flow or nitrogen flow, or pressure (gauge or absolute) for each regeneration cycle; and a carbon bed temperature monitoring device, capable of recording the carbon bed temperature after each regeneration and within 15 minutes of completing any cooling cycle are required.

* * * * *

(9) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (b)(2) of this section no longer applies and instead the owner or operator of the affected source must comply with § 63.508 for the flare.

(10) Beginning no later than the compliance dates specified in § 63.481(n), if the owner or operator vents emissions through a closed vent system to an adsorber(s) that cannot be regenerated or a regenerative adsorber(s) that is regenerated offsite, then the owner or operator must install a system of two or more adsorber units in series and comply with the requirements specified in paragraphs (b)(10)(i) through (b)(10)(iii) of this section.

(i) Conduct an initial performance test or design evaluation of the adsorber and establish the breakthrough limit and adsorber bed life.

(ii) Monitor the HAP or total organic compound (TOC) concentration through a sample port at the outlet of the first adsorber bed in series according to the schedule in paragraph (b)(10)(iii)(B) of this section. The owner or operator must measure the concentration of HAP or TOC using either a portable analyzer, in accordance with Method 21 of 40 CFR part 60, appendix A–7 using methane, propane, isobutylene, or the primary HAP being controlled as the calibration gas or Method 25A of 40 CFR part 60, appendix A–7 using methane, propane, or the primary HAP being controlled as the calibration gas.

(iii) Comply with paragraph (b)(10)(iii)(A) of this section, and comply with the monitoring frequency according to paragraph (b)(10)(iii)(B) of this section.

(A) The first adsorber in series must be replaced immediately when breakthrough, as defined in § 63.482, is detected between the first and second adsorber. The original second adsorber (or a fresh canister) will become the new first adsorber and a fresh adsorber will become the second adsorber. For purposes of this paragraph, ''immediately'' means within 8 hours of the detection of a breakthrough for adsorbers of 55 gallons or less, and within 24 hours of the detection of a breakthrough for adsorbers greater than 55 gallons. The owner or operator must monitor at the outlet of the first adsorber within 3 days of replacement to confirm it is performing properly.

(B) Based on the adsorber bed life established according to paragraph (b)(10)(i) of this section and the date the adsorbent was last replaced, conduct monitoring to detect breakthrough at least monthly if the adsorbent has more than 2 months of life remaining, at least weekly if the adsorbent has between 2 months and 2 weeks of life remaining, and at least daily if the adsorbent has 2 weeks or less of life remaining.

(11) Where sorbent injection is used, the following monitoring equipment is required for the sorbent injection system:

(i) A sorbent injection rate monitoring device (*e.g.,* weigh belt, weigh hopper, hopper flow measurement device) installed in a position that provides a representative measurement equipped with a continuous recorder to monitor the sorbent injection rate; and

(ii) A flow measurement device equipped with a continuous recorder to monitor the carrier gas flow rate.

* * * * *

(d) *Monitoring of bypass lines.* The owner or operator of a batch front-end process vent or aggregate batch vent stream using a vent system that contains bypass lines that could divert emissions away from a control device used to comply with § 63.487(a) or § 63.487(b) shall comply with either paragraph (d)(1) or (d)(2), and (d)(3) of this section. Except as specified in paragraph (d)(3) of this section, equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and pressure relief valves needed for safety purposes are not subject to this paragraph (d).

* * * * *

(3) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n):

(i) The use of a bypass line at any time on a closed vent system to divert emissions (subject to the emission standards in § 63.487) to the atmosphere or to a control device not meeting the requirements specified in this subpart is an emissions standards violation.

(ii) The last sentence in paragraph (d) of this section no longer applies. Instead, the exemptions specified in paragraph (d)(3)(ii)(A) and (d)(3)(ii)(B) of this section apply.

(A) Except for pressure relief devices subject to § 63.165(e)(4) of subpart H of this part, equipment such as low leg drains and equipment subject to the requirements of subpart H of this part are not subject to this paragraph (d).

(B) Open-ended valves or lines that use a cap, blind flange, plug, or second valve and follow the requirements specified in 40 CFR 60.482–6(a)(2), (b), and (c) or follow requirements codified in another regulation that are the same as 40 CFR 60.482–6(a)(2), (b), and (c) are not subject to this paragraph (d) of this section.

(e) * * *

(1) * * *

(i) For batch front-end process vents using a control device to comply with § 63.487(a)(2), the established level shall reflect the control efficiency established as part of the most recent compliance demonstration specified in § 63.490(c)(2).

* * * * *

(iii) For batch front-end process vents using a control device to comply with § 63.487(a)(3) and aggregate batch vent streams using a control device to comply with § 63.487 (b)(3), the established level shall reflect the level of control established as part of the most recent compliance demonstration specified in § 63.490(g).

* * * * *

■ 129. Amend § 63.490 by revising paragraphs (a), (c)(1)(i)(D), and (e)(1), and adding paragraph (g) as follows:

§ 63.490 Batch front-end process vents—performance test methods and procedures to determine compliance.

(a) *Use of a flare.* (1) Except as specified in paragraph (a)(2) of this section, when a flare is used to comply with § 63.487(a)(1) or (b)(1), the owner or operator of an affected source shall comply with § 63.504(c).

(2) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (a)(1) of this section no longer applies and instead the owner or operator of the affected source must comply with § 63.508 for the flare.

* * * * *

(c) * * *

(1) * * *

(i) * * *

(D) Method 18 or Method 25A of appendices A–6 and A–7 to 40 CFR part 60, respectively must be used to determine the concentration of organic HAP or TOC, as appropriate. ASTM

D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method. Alternatively, any other method or data that has been validated according to the applicable procedures in Method 301 of appendix A to this part may be used. The use of Method 25A must conform with the requirements in paragraphs (c)(1)(i)(D)(1) and (2) of this section.

(*1*) The organic HAP used as the calibration gas for Method 25A appendix A–7 to 40 CFR part 60 must be the single organic HAP representing the largest percent by volume of the emissions.

(*2*) The use of Method 25A appendix A–7 to 40 CFR part 60 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

* * * * *

(e) * * *

(1) For the purposes of this subpart, when the provisions of § 63.116(c) specify that Method 18 of appendix A–6 to 40 CFR part 60 must be used, Method 18 or Method 25A of appendix A–7 to 40 CFR part 60 may be used. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method. The use of Method 25A of appendix A–7 to 40 CFR part 60 must conform with the requirements in paragraphs (e)(1)(i) and (ii) of this section.

(i) The organic HAP used as the calibration gas for Method 25A of appendix A–7 to 40 CFR part 60 must be the single organic HAP representing the largest percent by volume of the emissions.

(ii) The use of Method 25A of appendix A–7 to 40 CFR part 60 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.

* * * * *

(g) *Testing for compliance with § 63.487(a)(3) and (b)(3) [dioxins and furans].* Except as specified in paragraph (g)(7) of this section, an owner or operator complying with § 63.487(a)(3) and/or (b)(3) must conduct a performance test using the procedures in paragraphs (g)(1) through (6) of this section. Conduct subsequent performance tests no later than 60 calendar months after the previous performance test.

(1) The performance test must consist of three test runs. Collect at least 3 dry standard cubic meters of gas per test run.

(2) Use Method 1 or 1A of appendix A–1 to 40 CFR part 60 to select the sampling sites at the sampling location. The sampling location must be at the outlet of the final control device.

(3) Determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of appendix A–2 to 40 CFR part 60.

(4) Use Method 4 of appendix A–3 to 40 CFR part 60 to convert the volumetric flowrate to a dry basis.

(5) Measure the concentration of each tetra- through octa-chlorinated dioxin and furan congener emitted using Method 23 of appendix A–7 to 40 CFR part 60.

(i) For each dioxin and furan congener, multiply the congener concentration by its corresponding toxic equivalency factor specified in table 10 to this subpart. For determination of toxic equivalency, zero may be used for congeners with a concentration less than the estimated detection limit (EDL). For congeners with estimated maximum pollutant concentration (EMPC) results, if the value is less than the EDL, zero may be used. Otherwise, the EMPC value must be used in the calculation of toxic equivalency.

(ii) Sum the products calculated in accordance with paragraph (g)(5)(i) of this section to obtain the total concentration of dioxins and furans emitted in terms of toxic equivalency.

(6) The concentration of dioxins and furans shall be corrected to 3 percent oxygen. Use Method 3A of appendix A–2 to 40 CFR part 60 or the manual method in ANSI/ASME PTC 19.10–1981 (incorporated by reference, see § 63.14) to determine the oxygen concentration (%O2d). The oxygen concentration must be determined concurrently with Method 23 of appendix A–7 to 40 CFR part 60. The concentration corrected to 3 percent oxygen (Cc) shall be computed using the following equation:

$$C_c = C_m\left(\frac{17.9}{20.9 - \%O_{2d}}\right)$$

Where:

C_c = Concentration of dioxins and furans corrected to 3 percent oxygen, dry basis, nanograms per standard cubic meter.

C_m = Concentration of dioxins and furans, dry basis, nanograms per standard cubic meter.

$\%O_2d$ = Concentration of oxygen, dry basis, percent by volume.

(7) An owner or operator is not required to conduct a performance test when either a boiler or process heater burning hazardous waste, or hazardous waste incinerator, is used for which the owner or operator:

(i) Has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H;

(ii) Has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(iii) Meets the requirement specified in paragraph (g)(7)(v) of this section, and has submitted a Notification of Compliance under § 63.1207(j) and complies with the requirements of subpart EEE of this part; or

(iv) Meets the requirement specified in paragraph (g)(7)(v) of this section, complies with subpart EEE of this part, and will submit a Notification of Compliance under § 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

(v) The owner and operator may not waive performance testing pursuant to § 63.1207(d)(4) and each performance test required by § 63.1207(d) must show compliance with the dioxins and furans emission limit specified in § 63.487(a)(3) and (b)(3), as applicable.

■ 130. Amend § 63.491 by:

■ a. Revising paragraph (b)(3) introductory text;

■ b. Adding paragraphs (b)(3)(iv) and (b)(6);

■ c. Revising and republishing paragraph (d)(1);

■ d. Revising paragraphs (e)(3) and (e)(4) introductory text;
■ e. Adding paragraph (e)(6);
■ f. Revising paragraph (f)(3); and
■ g. Adding paragraph (h).

The revisions, additions and republication read as follows:

§ 63.491 Batch front-end process vents—recordkeeping requirements.

* * * * *

(b) * * *

(3) Except as specified in paragraph (b)(3)(iv) of this section, when using a flare to comply with § 63.487(a)(1):

* * * * *

(iv) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraphs (b)(3)(i) through (b)(3)(iii) of this section no longer apply and instead the owner or operator of the affected source must keep the records specified in § 63.108(m) of subpart F of this part and § 63.508, readily accessible when using a flare to comply with § 63.487(a)(1).

* * * * *

(6) Records of the dioxins and furans concentration, as determined in § 63.490(g).

* * * * *

(d) * * *

(1) The owner or operator of a Group 2 batch front-end process vent required to comply with § 63.487(g) shall keep the following records readily accessible:

(i) Except as specified in paragraph (d)(1)(iii) of this section, records designating the established batch mass input limitation required by § 63.487(g)(1) and specified in § 63.490(f).

(ii) Records specifying the mass of HAP or material charged to the batch unit operation.

(iii) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (d)(1)(i) of this section no longer applies.

* * * * *

(e) * * *

(3) Except as specified in paragraph (e)(6) of this section, hourly records of whether the flow indicator for bypass lines specified under § 63.489(d)(1) was operating and whether a diversion was detected at any time during the hour. Also, records of the times of all periods when the vent is diverted from the control device, or the flow indicator specified in § 63.489(d)(1) is not operating.

(4) Except as specified in paragraph (e)(6) of this section, where a seal or closure mechanism is used to comply with § 63.489(d)(2), hourly records of whether a diversion was detected at any time are not required.

* * * * *

(6) For each flow event from a bypass line subject to the requirements in § 63.489(d) for each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), the owner or operator must also maintain records sufficient to determine whether or not the detected flow included flow requiring control. For each flow event from a bypass line requiring control that is released either directly to the atmosphere or to a control device not meeting the requirements in this subpart, the owner or operator must 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.

(f) * * *

(3) For demonstrating compliance with the monitoring of bypass lines as specified in § 63.489(d), records as specified in paragraph (e)(3) or (4) of this section, and (e)(6) of this section as appropriate.

* * * * *

(h) *Maintenance vent compliance records for batch front-end process vents.* For each maintenance vent opening subject to the requirements of § 63.487(i), owners and operators must keep the applicable records specified in paragraphs (h)(1) through (5) of this section.

(1) Owners and operators must 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 § 63.487(i). The current copy of the procedures must be retained and available on-site at all times. Previous versions of the standard site procedures, as applicable, must be retained for five years.

(2) If complying with the requirements of § 63.487(i)(1)(i), and the concentration of the vapor at the time of the vessel opening exceeds 10 percent of its LEL, identification of the maintenance vent, the process units or equipment associated with the maintenance vent, the date of maintenance vent opening, and the concentration of the vapor at the time of the vessel opening.

(3) If complying with the requirements of § 63.487(i)(1)(ii), and either the vessel pressure at the time of the vessel opening exceeds 5 psig or the concentration of the vapor at the time of the active purging was initiated exceeds 10 percent of its LEL, 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 concentration of the vapors in the equipment when active purging was initiated.

(4) If complying with the requirements of § 63.487(i)(1)(iii), records of the estimating procedures used to determine the total quantity of VOC in the equipment and the type and size limits of equipment that contain less than 50 pounds of VOC at the time of maintenance vent opening. For each maintenance vent opening that contains greater than 50 pounds of VOC for which the deinventory procedures specified in paragraph (h)(1) of this section are not followed or for which the equipment opened exceeds the type and size limits established in the records specified in this paragraph (h)(4), records that identify 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.

(5) If complying with the requirements of § 63.487(i)(1)(iv), identification of the maintenance vent, the process units or equipment associated with the maintenance vent, records documenting actions taken to comply with other applicable alternatives and why utilization of this alternative was required, the date of maintenance vent opening, the equipment pressure and concentration of the vapors in the equipment at the time of discharge, an indication of whether active purging was performed and the pressure of the equipment during the installation or removal of the blind if active purging was used, the duration the maintenance vent was open during the blind installation or removal process, 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.

■ 131. Amend § 63.492 by revising paragraph (f) and adding paragraph (g) to read as follows:

§ 63.492 Batch front-end process vents—reporting requirements.

* * * * *

(f) Owners or operators of affected sources complying with § 63.489(d), shall comply with paragraph (f)(1) or (2) of this section, as appropriate.

(1) Submit reports of the times of all periods recorded under § 63.491(e)(3) when the batch front-end process vent is diverted away from the control device through a bypass line, with the next Periodic Report. Include the start date, start time and duration in hours of each period.

(2) Submit reports of all occurrences recorded under § 63.491(e)(4) in which the seal mechanism is broken, the bypass line damper or valve position has changed, or the key to unlock the bypass line damper or valve was checked out, with the next Periodic Report. Include the start date, start time and duration in hours of each period.

(g) For any maintenance vent release exceeding the applicable limits in § 63.487(i)(1), the Periodic Report must include the information specified in paragraphs (g)(1) through (4) of this section. For the purposes of this reporting requirement, if an owner or operator complies with § 63.487(i)(1)(iv), then the owner or operator must report each venting event conducted under those provisions and include an explanation for each event as to why utilization of this alternative was required.

(1) Identification of the maintenance vent and the equipment served by the maintenance vent.

(2) The date and time the maintenance vent was opened to the atmosphere.

(3) The LEL in percent, vessel pressure in psig, or mass in pounds of VOC in the equipment, as applicable, at the start of atmospheric venting. If the 5 psig vessel pressure option in § 63.487(i)(1)(ii) was used and active purging was initiated while the concentration of the vapor was 10 percent or greater of its LEL, also include the concentration of the vapors at the time active purging was initiated.

(4) An estimate of the mass in pounds of organic HAP released during the entire atmospheric venting event.

■ 132. Amend § 63.494 by revising paragraph (a)(4) introductory text, adding paragraph (a)(7), revising paragraph (d), and adding paragraph (e) to read as follows:

§ 63.494 Back-end process provisions—residual organic HAP and emission limitations.

(a) * * *

(4) In addition to the requirements specified in paragraph (a)(7) of this section, the organic HAP emissions from back-end processes at affected sources producing butyl rubber, epichlorohydrin elastomer, neoprene, and nitrile butadiene rubber shall not exceed the limits determined in accordance with paragraphs (a)(4)(i) through (iv) of this section for any consecutive 12-month period. The specific limitation for each elastomer type shall be determined based on the calculation or the emissions level provided in paragraphs (a)(4)(i) through (iv) of this section divided by the base year elastomer product that leaves the stripping operation (or the reactor(s), if the plant has no stripper(s)). The limitation shall be calculated and submitted in accordance with § 63.499(f)(1).

* * * * *

(7) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(o), if the back-end process vent contains chloroprene such that it is considered to be in chloroprene service, as defined in § 63.482, then the owner or operator must comply with the requirements of paragraphs (a)(7)(i) through (iii) of this section in addition to all other applicable requirements specified in § 63.483 and elsewhere in this section.

(i) Reduce emissions of chloroprene by venting emissions through a closed vent system to a non-flare control device that reduces chloroprene by greater than or equal to 98 percent by weight, or to a concentration less than 1 ppmv for each process vent or to less than 5 pounds per year for all combined process vents within the process. If a combustion device is used, the chloroprene concentration of 1 ppmv must be corrected to 3 percent oxygen.

(ii) To demonstrate compliance with the emission limits specified in paragraph (a)(7)(i) of this section for back-end process vents in chloroprene service, owners and operators must meet the requirements specified in § 63.510.

(iii) An owner or operator may designate a back-end process vent in chloroprene service 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; however, owners and operators may not release more than 1.0 tons of chloroprene from all maintenance vents combined (*i.e.,* including maintenance vents subject to this paragraph (a)(7)(iii), § 63.485(z), or § 63.487(i)(4)) per any consecutive 12-month period. The owner or operator must keep monthly records of the quantity in tons of chloroprene released from each maintenance vent and include a description of the method used to estimate this quantity.

* * * * *

(d) Except as specified in paragraph (e) of this section, if the owner or operator complies with the residual organic HAP limitations in paragraph (a)(1) through (3) of this section using a flare, the owner or operator of an affected source shall comply with the requirements in § 63.504(c).

(e) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (d) of this section no longer applies and instead if the owner or operator complies with the residual organic HAP limitations in paragraph (a)(1) through (3) of this section using a flare, the owner or operator of the affected source must comply with § 63.508 for the flare.

■ 133. Amend § 63.496 by revising paragraphs (b)(5)(iii) and (b)(7)(i) to read as follows:

§ 63.496 Back-end process provisions—procedures to determine compliance with residual organic HAP limitations using control or recovery devices.

* * * * *

(b) * * *

(5) * * *

(iii) To determine the inlet and outlet total organic HAP concentrations, the owner or operator must use Method 18 or Method 25A of appendices A–6 and A–7 to 40 CFR part 60, respectively. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method. Alternatively, any other method or data that has been validated according to the applicable procedures in Method 301 of appendix A to this part may be used. The minimum sampling time for each run must be in accordance with paragraph (b)(1) of this section, during which either an integrated sample or grab samples shall be taken. If grab sampling is used, then the samples must be taken at approximately equal intervals during the run, with the time between samples no greater than 15 minutes.

* * * * *

(7) * * *

(i) A flare. (A) Except as specified in paragraph (b)(7)(i)(B) of this section, the owner or operator shall demonstrate compliance as provided in § 63.504(c).

(B) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (b)(7)(i)(A) of this section no longer applies and instead the owner or operator of the affected source must comply with § 63.508 for the flare.

* * * * *

■ 134. Amend § 63.497 by revising paragraphs (a) introductory text, (a)(2) and (6), adding paragraphs (a)(7) and (8), revising paragraph (d) introductory text, and adding paragraph (d)(3) to read as follows:

§ 63.497 Back-end process provisions—monitoring provisions for control and recovery devices used to comply with residual organic HAP limitations.

(a) An owner or operator complying with the residual organic HAP limitations in § 63.494(a)(1) through (3) using control or recovery devices, or a combination of stripping and control or recovery devices, shall install the monitoring equipment specified in paragraphs (a)(1) through (7) of this section, as appropriate.

* * * * *

(2) Where a flare is used, except as specified in paragraph (a)(7) of this section, a device (including, but not limited to, a thermocouple, ultra-violet beam sensor, or infrared sensor) capable of continuously detecting the presence of a pilot flame is required.

* * * * *

(6) Except as specified in paragraph (a)(8) of this section, for a carbon adsorber, an integrating regeneration steam flow, nitrogen flow, or pressure monitoring device having an accuracy of at least ±10 percent of the flow rate, level, or pressure, capable of recording the total regeneration steam flow or nitrogen flow, or pressure (gauge or absolute) for each regeneration cycle; and a carbon bed temperature monitoring device, capable of recording the carbon bed temperature after each regeneration and within 15 minutes of completing any cooling cycle are required.

(7) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (a)(2) of this section no longer applies and instead the owner or operator of the affected source must comply with § 63.508 for the flare.

(8) Beginning no later than the compliance dates specified in § 63.481(n), if the owner or operator vents emissions through a closed vent system to an adsorber(s) that cannot be regenerated or a regenerative adsorber(s) that is regenerated offsite, then the owner or operator must install a system of two or more adsorber units in series and comply with the requirements specified in paragraphs (a)(8)(i) through (iii) of this section.

(i) Conduct an initial performance test or design evaluation of the adsorber and establish the breakthrough limit and adsorber bed life.

(ii) Monitor the HAP or total organic compound (TOC) concentration through a sample port at the outlet of the first adsorber bed in series according to the schedule in paragraph (a)(8)(iii)(B) of this section. The owner or operator must measure the concentration of HAP or TOC using either a portable analyzer, in accordance with Method 21 of 40 CFR part 60, appendix A–7 using methane, propane, isobutylene, or the primary HAP being controlled as the calibration gas or Method 25A of 40 CFR part 60, appendix A–7 using methane, propane, or the primary HAP being controlled as the calibration gas.

(iii) Comply with paragraph (a)(8)(iii)(A) of this section, and comply with the monitoring frequency according to paragraph (a)(8)(iii)(B) of this section.

(A) The first adsorber in series must be replaced immediately when breakthrough, as defined in § 63.482, is detected between the first and second adsorber. The original second adsorber (or a fresh canister) will become the new first adsorber and a fresh adsorber will become the second adsorber. For purposes of this paragraph, ''immediately'' means within 8 hours of the detection of a breakthrough for adsorbers of 55 gallons or less, and within 24 hours of the detection of a breakthrough for adsorbers greater than 55 gallons. The owner or operator must monitor at the outlet of the first adsorber within 3 days of replacement to confirm it is performing properly.

(B) Based on the adsorber bed life established according to paragraph (a)(8)(i) of this section and the date the adsorbent was last replaced, conduct monitoring to detect breakthrough at least monthly if the adsorbent has more than 2 months of life remaining, at least weekly if the adsorbent has between 2 months and 2 weeks of life remaining, and at least daily if the adsorbent has 2 weeks or less of life remaining.

* * * * *

(d) The owner or operator of an affected source with a controlled back-end process vent using a vent system that contains bypass lines that could divert a vent stream away from the control or recovery device used to comply with § 63.494(a)(1) through (3), shall comply with either paragraph (d)(1) or (d)(2), and (d)(3) of this section. Except as specified in paragraph (d)(3) of this section, equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and pressure relief valves needed for safety purposes are not subject to this paragraph.

* * * * *

(3) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n):

(i) The use of a bypass line at any time on a closed vent system to divert emissions (subject to the emission standards in § 63.487) to the atmosphere or to a control device not meeting the requirements specified in this subpart is an emissions standards violation.

(ii) The last sentence in paragraph (d) of this section no longer applies. Instead, the exemptions specified in paragraph (d)(3)(ii)(A) and (d)(3)(ii)(B) of this section apply.

(A) Except for pressure relief devices subject to § 63.165(e)(4) of subpart H of this part, equipment such as low leg drains and equipment subject to the requirements of subpart H of this part are not subject to this paragraph (d) of this section.

(B) Open-ended valves or lines that use a cap, blind flange, plug, or second valve and follow the requirements specified in 40 CFR 60.482–6(a)(2), (b), and (c) or follow requirements codified in another regulation that are the same as 40 CFR 60.482–6(a)(2), (b), and (c) are not subject to this paragraph (d) of this section.

■ 135. Amend § 63.498 by:

■ a. Revising paragraph (a) introductory text;

■ b. Revising and republishing paragraph (d); and

■ c. Adding paragraph (f).

The addition, revisions and republication read as follows:

§ 63.498 Back-end process provisions—recordkeeping.

(a) Each owner or operator shall maintain the records specified in paragraphs (a)(1) through (4), and paragraphs (b) through (f) of this section, as appropriate.

* * * * *

(d) Each owner or operator of a back-end process operation using control or recovery devices to comply with a residual organic HAP limitation in § 63.494(a)(1) through (3), shall maintain the records specified in paragraphs (d)(1) through (5) of this section. The recordkeeping requirements contained in paragraphs (d)(1) through (4) pertain to the results of the testing required by § 63.496(b), for each of the three required test runs.

(1) The uncontrolled residual organic HAP content in the latex or dry crumb rubber, as required to be determined by § 63.496(b)(3), including the test results of the analysis;

(2) The total quantity of material (weight of latex or dry crumb rubber) processed during the test run, recorded in accordance with § 63.496(b)(4);

(3) The organic HAP emissions at the inlet and outlet of the control or recovery device, determined in accordance with § 63.496(b)(5) through (8), including all test results and calculations.

(4) The residual organic HAP content, adjusted for the control or recovery device emission reduction, determined in accordance with § 63.496(c)(1).

(5) Each owner or operator using a control or recovery device shall keep the following records readily accessible:

(i) Continuous records of the equipment operating parameters specified to be monitored under § 63.497(a) or specified by the Administrator in accordance with § 63.497(b). For flares, the records specified in § 63.508, if applicable, and table 3 to subpart G of this part shall be maintained in place of continuous records.

(ii) Records of the daily average value of each continuously monitored parameter for each operating day, except as provided in paragraphs (d)(5)(ii)(D) through (d)(5)(ii)(F) 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, except as provided in paragraph (d)(5)(ii)(B) of this section. The average shall cover a 24-hour period if operation is continuous, or the number of hours of operation per operating day if operation is not continuous.

(B) 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 computing the hourly or daily averages. In addition, monitoring data recorded during periods of non-operation of the EPPU (or specific portion thereof) resulting in cessation of organic HAP emissions, shall not be included in computing the hourly or daily averages. Records shall be kept of the times and durations of all such periods and any other periods of process or control device operation when monitors are not operating.

(C) The operating day shall be the period defined in the operating permit or the Notification of Compliance Status in § 63.506(e)(5) or (8). It may be from midnight to midnight or another 24-hour period.

(D) If all recorded values for a monitored parameter during an operating day are below the maximum, or above the minimum, level established in the Notification of Compliance Status in § 63.506(e)(5) or in the operating permit, the owner or operator may record that all values were below the maximum or above the minimum level, rather than calculating and recording a daily average for that operating day.

(E) Except as specified in paragraph (d)(5)(ii)(F) of this section, for flares, records of the times and duration of all periods during which the pilot flame is absent, shall be kept rather than daily averages. The records specified in this paragraph are not required during periods when emissions are not routed to the flare.

(F) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (d)(5)(ii)(E) of this section no longer applies and instead the owner or operator of the affected source must keep the records specified in § 63.108(m) of subpart F of this part and § 63.508.

(iii) Except as specified in paragraph (d)(5)(v) of this section, hourly records of whether the flow indicator specified under § 63.497(d)(1) was operating and whether a diversion was detected at any time during the hour, as well as records of the times of all periods when the vent stream is diverted from the control device or the flow indicator is not operating.

(iv) Except as specified in paragraph (d)(5)(v) of this section, where a seal mechanism is used to comply with § 63.497(d)(2), hourly records of flow are not required.

(A) For compliance with § 63.497(d)(2), the owner or operator shall record whether the monthly visual inspection of the seals or closure mechanisms has been done, and shall record instances when the seal mechanism is broken, the bypass line damper or valve position has changed, or the key for a lock-and-key type configuration has been checked out, and records of any car-seal that has broken.

(B) [Reserved]

(v) For each flow event from a bypass line subject to the requirements in § 63.127(d) of subpart G of this part for each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), the owner or operator must also maintain records sufficient to determine whether or not the detected flow included flow requiring control. For each flow event from a bypass line requiring control that is released either directly to the atmosphere or to a control device not meeting the requirements in this subpart, the owner or operator must 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.

* * * * *

(f) Owners and operators subject to § 63.494(a)(7), must keep the records specified in paragraphs (f)(1) and (2) of this section in addition to those records specified elsewhere in this section.

(1) For back-end process vents in chloroprene service, include all uncontrolled, undiluted chloroprene concentration measurements, and the calculations used to determine the total uncontrolled chloroprene mass emission rate for the sum of all vent gas streams.

(2) The owner or operator must keep records of all periods during which operating values are outside of the applicable operating limits specified in § 63.510(b)(4) through (6) when regulated material is being routed to the non-flare control device. The record must specify the operating parameter, the applicable limit, and the highest (for maximum operating limits) or lowest (for minimum operating limits) value recorded during the period.

■ 136. Amend § 63.499 by adding paragraph (g) as follows:

§ 63.499 Back-end process provisions—reporting.

* * * * *

(g) Owners and operators subject to § 63.494(a)(7), must include in the periodic report, the records for the periods specified in § 63.498(f)(2). Indicate the start date, start time and duration in hours for each period.

■ 137. Amend § 63.500 by revising paragraph (c)(1)(iii) introductory text to read as follows:

§ 63.500 Back-end process provisions—carbon disulfide limitations for styrene butadiene rubber by emulsion processes.

* * * * *

(c) * * *

(1) * * *

(iii) To determine compliance with the carbon disulfide concentration limit in paragraph (a) of this section, the owner or operator shall use Method 18 or Method 25A of appendices A–6 and A–7 to 40 CFR part 60, respectively to measure carbon disulfide. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section

1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method. Alternatively, any other method or data that has been validated according to the applicable procedures in Method 301 of appendix A to this part, may be used. The following procedures shall be used to calculate carbon disulfide concentration:

* * * * *

■ 138. Amend § 63.501 by revising paragraphs (a) introductory text, revising and republishing (a)(10) and (20), and (b), and adding paragraphs (d), (e), and (f) to read as follows:

§ 63.501 Wastewater provisions.

(a) Except as specified in paragraphs (c) through (f) of this section, the owner or operator of each affected source shall comply with the requirements of §§ 63.132 through 63.147 for each process wastewater stream originating at an affected source, with the requirements of § 63.148 for leak inspection provisions, and with the requirements of § 63.149 for equipment that is subject to § 63.149, with the differences noted in paragraphs (a)(1) through (23) of this section. Further, the owner or operator of each affected source shall comply with the requirements of § 63.105(a) for maintenance wastewater, as specified in paragraph (b) of this section.

* * * * *

(10) The provisions of paragraphs (a)(10)(i) through (iv) of this section clarify the organic HAP that an owner or operator must consider when complying with the requirements of §§ 63.132 through 63.149.

(i) Owners and operators are exempt from all requirements in §§ 63.132 through 63.149 that pertain solely and exclusively to organic HAP listed on table 8 to 40 CFR part 63, subpart G.

(ii) When §§ 63.132 through 63.149 refer to table 9 compounds, the owner or operator is only required to consider compounds that meet the definition of organic HAP in § 63.482 and that are listed in table 9 to 40 CFR part 63, subpart G, for the purposes of this subpart.

(iii) When §§ 63.132 through 63.149 refer to compounds in table 36 to 40 CFR part 63, subpart G, or compounds in List 1 and/or List 2, as listed in table 36 to 40 CFR part 63, subpart G, the owner or operator is only required to consider compounds that meet the definition of organic HAP in § 63.482 and that are listed in table 36 to 40 CFR part 63, subpart G, for the purposes of this subpart.

(iv) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(o), the provisions specified in § 63.132(c)(1)(iii) do not apply. Instead, if the wastewater stream contains chloroprene such that it is considered to be in chloroprene service, as defined in § 63.482, then the wastewater stream is a Group 1 wastewater stream. For wastewater streams in chloroprene service, owners and operators must also meet the requirements specified in § 63.510.

* * * * *

(20) When the provisions of § 63.139(c)(1)(ii), § 63.145(d)(4), or § 63.145(i)(2) specify that Method 18 of appendix A–6 to 40 CFR part 60 must be used, Method 18 or Method 25A of appendices A–6 and A–7 to 40 CFR part 60, respectively, may be used for the purposes of this subpart. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method. The use of Method 25A must conform with the requirements in paragraphs (a)(20)(i) and (ii) of this section.

(i) The organic HAP used as the calibration gas for Method 25A of appendix A–7 to 40 CFR part 60 must be the single organic HAP representing the largest percent by volume of the emissions.

(ii) The use of Method 25A of appendix A–7 to 40 CFR part 60 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

(b) Except for those streams exempted by paragraphs (c) and (d) of this section, the owner or operator of each affected source shall comply with the requirements for maintenance wastewater in § 63.105, except that when § 63.105(a) refers to ‘‘organic HAPs listed in table 9 to subpart G of this part,’’ the owner or operator is only required to consider compounds that meet the definition of organic HAP in § 63.482 and that are listed in table 9 to subpart G of this part, for the purposes of this subpart.

* * * * *

(d) Substitute ‘‘For each affected source as described in § 63.480, on and after July 15, 2027,’’ for each occurrence of ‘‘For each source as defined in § 63.101, on and after July 15, 2027,’’.

(e) Substitute ‘‘For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n),’’ for each occurrence of ‘‘For each source as defined in § 63.101, beginning no later than the compliance dates specified in § 63.100(k)(10),’’.

(f) Substitute ‘‘§ 63.508’’ for each occurrence of ‘‘§ 63.108’’.

■ 139. Amend § 63.502 by revising the section heading, paragraphs (a) (j), (k), and (n) to read as follows:

§ 63.502 Equipment leak, fenceline monitoring, and heat exchange system provisions.

(a) The owner or operator of each affected source, shall comply with the requirements of subpart H of this part, with the exceptions noted in paragraphs (a)(1) through (7), and (b) through (m) of this section. Except as specified in § 63.170(b), surge control vessels required to be controlled by subpart H may, alternatively, comply with the Group 1 storage vessel provisions specified in § 63.484.

(1) Substitute ‘‘For each affected source as described in § 63.480, on and after July 15, 2027,’’ for each occurrence of ‘‘For each source as defined in § 63.101, and for each source as defined in § 63.191, on and after July 15, 2027,’’.

(2) Substitute ‘‘For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n),’’ for each occurrence of ‘‘For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(10),’’.

(3) Substitute ‘‘For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(o),’’ for each occurrence of ‘‘For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(11),’’.

(4) Substitute ‘‘For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(p),’’ for each occurrence of ‘‘For each source as defined in § 63.101, and for each source as defined in § 63.191, beginning no later than the compliance dates specified in § 63.100(k)(12),’’.

(5) Substitute ‘‘§ 63.508’’ for each occurrence of ‘‘§ 63.108’’.

(6) Substitute ‘‘in chloroprene service’’ for each occurrence of ‘‘in ethylene oxide service’’.

(7) If an affected source uses, produces, stores, or emits chloroprene, the action level for chloroprene in § 63.184(d)(3) is 0.3 $\mu g/m^3$ on an annual average basis for the purposes of this subpart. Additionally, the sampling period Δc in § 63.184(e)(4)(iii) and (f)(1)(iii) is 0.3 $\mu g/m^3$ instead of 0.8 $\mu g/m^3$ for the purposes of this subpart.

* * * * *

(j) When the provisions of subpart H of this part specify that Method 18 of appendix A–6 to 40 CFR part 60 must be used, either Method 18 or Method 25A of appendices A–6 and A–7 to 40 CFR part 60, respectively, may be used for the purposes of this subpart. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method. The use of Method 25A must conform with the requirements in paragraphs (j)(1) and (2) of this section.

(1) The organic HAP used as the calibration gas for Method 25A of appendix A–7 to 40 CFR part 60 must be the single organic HAP representing the largest percent by volume of emissions.

(2) The use of Method 25A of appendix A–7 to 40 CFR part 60 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.

(k)(1) Except as specified in paragraph (k)(2) of this section, an owner or operator using a flare to comply with the requirements of this section shall conduct a compliance demonstration as specified in § 63.504(c).

(2) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), paragraph (k)(1) of this section no longer applies and instead the owner or operator of the affected source must comply with § 63.508 for the flare.

* * * * *

(n) The owner or operator of each affected source shall comply with the requirements of § 63.104 for heat exchange systems, with the exceptions noted in paragraphs (n)(1) through (8) of this section.

(1) When the term ''chemical manufacturing process unit'' is used in § 63.104, the term ''elastomer product process unit'' (or EPPU) shall apply for the purposes of this subpart, with the exception noted in paragraph (n)(2) of this section.

(2) When the phrase ''a chemical manufacturing process unit meeting the conditions of § 63.100(b)(1) through (b)(3) of this subpart, except for chemical manufacturing process units meeting the condition specified in § 63.100(c) of this subpart'' is used in the first sentence of § 63.104(a), the term ''an EPPU, except for EPPUs meeting the condition specified in § 63.480(b)'' shall apply for the purposes of this subpart. When the phrase ''a chemical manufacturing process unit meeting the conditions of § 63.100(b)(1) through (b)(3),'' is used in the last sentence of § 63.104(a) of subpart F of this part, the term ''an EPPU'' shall apply for purposes of this subpart.

(3) When § 63.104 refers to table 4 to subpart F of this part or table 9 to subpart G of this part, the owner or operator is only required to consider organic HAP listed on table 5 to this subpart.

(4) When § 63.104(c)(3) specifies the monitoring plan retention requirements, and when § 63.104(f)(1) refers to the record retention requirements in § 63.103(c)(1), the requirements in § 63.506(a) and § 63.506(h) shall apply, for the purposes of this subpart.

(5) When § 63.104(f)(2) requires information to be reported in the Periodic Reports required by § 63.152(c), the owner or operator shall instead report the information specified in § 63.104(f)(2) in the Periodic Reports required by § 63.506(e)(6), for the purposes of this subpart.

(6) The compliance date for heat exchange systems subject to the provisions of this section is specified in § 63.481(d)(6).

(7) Substitute ''Beginning no later than the compliance dates specified in § 63.481(n),'' for each occurrence of ''Beginning no later than the compliance dates specified in § 63.100(k)(10),''.

(8) § 63.104(k) of subpart F of this part does not apply. Instead for each source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), owners and operators must not inject water into or dispose of water through any heat exchange system in an EPPU if the water contains any amount of chloroprene, has been in contact with any process stream containing chloroprene, or the water is considered wastewater as defined in § 63.482.

■ 140. Amend § 63.503 by revising paragraphs (a)(3), (g)(2)(ii) introductory text and (g)(2)(iii)(B)(*2*), adding paragraph (g)(2)(iii)(B)(*4*), and revising paragraphs (g)(7)(ii) introductory text, (m)(1)(ii) and (m)(2)(i) to read as follows:

§ 63.503 Emissions averaging provisions.

(a) * * *

(3) For the purposes of the provisions in this section, whenever Method 18 of appendix A–6 to 40 CFR part 60 is specified within the paragraphs of this section or is specified by reference through provisions outside this section, Method 18 or Method 25A of appendices A–6 and A–7 to 40 CFR part 60, respectively, may be used. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method. The use of Method 25A, must conform with the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) The organic HAP used as the calibration gas for Method 25Aof appendix A–7 to 40 CFR part 60 must be the single organic HAP representing the largest percent by volume of the emissions.

(ii) The use of Method 25A of appendix A–7 to 40 CFR part 60, 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.

* * * * *

(g) * * *

(2) * * *

(ii) $ECFEPV_{iu}$ for each continuous front-end process vent i shall be calculated using equation 34.

$$ECFEPV_{iu} = \left(2.494\times10^{-9}\right)Qh\left(\sum_{j=1}^{n}C_jM_j\right) \qquad [Eq.\ 34]$$

Where:

$ECFEPV_{iu}$ = Uncontrolled continuous front-end process vent emission rate from continuous front-end process vent i, Mg/month.

Q = Vent stream flow rate, dry standard m^3/min, measured using Method 2, 2A, 2C, or 2D of 40 CFR part 60, appendix A, as appropriate.

h = Monthly hours of operation during which positive flow is present in the continuous front-end process vent, hr/month.

C_j = Concentration, ppmv, dry basis, of organic HAP j as measured by Method 18 or Method 25A of appendices A–6 and A–7 to 40 CFR part 60, respectively, or ASTM D6420–18 (incorporated by reference, see § 63.14).

M_j = Molecular weight of organic HAP j, gram per gram-mole.

n = Number of organic HAP in stream.

* * * * *

(iii) * * *

(B) * * *

(*2*) For determining debits from Group 1 continuous front-end process vents, product recovery devices shall not be considered control devices and shall not be assigned a percent reduction in calculating $ECFEPV_{iACTUAL}$. The sampling site for measurement of uncontrolled emissions shall be after the final uncontrolled recovery device. However, as provided in § 63.113(a)(3), a Group 1 continuous front-end process vent may add sufficient product recovery to raise the TRE index value above 1.0, thereby becoming a Group 2 continuous front-end process vent. Such a continuous front-end process vent is not a Group 1 continuous front-end process vent and should, therefore, not be included in determining debits under this paragraph, except as specified in paragraph (g)(2)(iii)(B)(*4*) of this section.

* * * * *

(*4*) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), that last two sentences of paragraph (g)(2)(iii)(B)(*2*) of this section no longer apply.

* * * * *

(7) * * *

(ii) $EABV_{iu}$ for each aggregate batch vent i shall be calculated using equation 39.

$$EABV_{iu} = \left(2.494\times10^{-9}\right)Qh\left(\sum_{j=1}^{n}C_jM_j\right) \qquad [Eq.\ 39]$$

Where:

$EABV_{iu}$ = Uncontrolled aggregate batch vent emission rate from aggregate batch vent i, Mg/month.

Q = Vent stream flow rate, dry standard cubic meters per minute, measured using Method 2, 2A, 2C, or 2D of 40 CFR part 60, appendix A, as appropriate.

h = Monthly hours of operation during which positive flow is present from the aggregate batch vent stream, hr/month.

C_j = Concentration, ppmv, dry basis, of organic HAP j as measured by Method 18 of appendix A–6 to 40 CFR part 60 or ASTM D6420–18 (incorporated by reference, see § 63.14).

M_j = Molecular weight of organic HAP j, gram per gram-mole.

n = Number of organic HAP in the stream.

* * * * *

(m) * * *

(1) * * *

(ii) Conduct initial and subsequent performance tests to determine percent reduction as specified in § 63.116 and as required by § 63.485; and

* * * * *

(2) * * *

(i) Determine the flow rate, organic HAP concentration, and TRE index value according to the procedures specified in § 63.115, except as specified in § 63.113(a)(4) and § 63.485(x); and

* * * * *

■ 141. Amend § 63.504 by revising paragraphs (a) introductory text and (a)(1) introductory text, adding paragraph (a)(1)(iii), revising paragraph (c) introductory text and adding paragraph (c)(4) to read as follows:

§ 63.504 Additional requirements for performance testing.

(a) Performance testing shall be conducted in accordance with § 63.7(a)(1), (a)(3), (d), (e)(1) and (2), (e)(4), (g), and (h), with the exceptions specified in paragraphs (a)(1) through (5) of this section and the additions specified in paragraph (b) of this section. Sections 63.484 through 63.501 also contain specific testing requirements. Beginning no later than the compliance dates specified in § 63.481(n), conduct subsequent performance tests no later than 60 calendar months after the previous performance test.

(1) Except as specified in paragraph (a)(1)(iii) of this section, performance tests shall be conducted at maximum representative operating conditions achievable during one of the time periods described in paragraph (a)(1)(i) of this section, without causing any of the situations described in paragraph (a)(1)(ii) of this section to occur. 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.

* * * * *

(iii) Beginning no later than the compliance dates specified in § 63.481(n), paragraphs (a)(1)(i) and (ii) of this section no longer applies and instead the owner or operator must conduct performance tests under such conditions as the Administrator specifies based on representative performance of the affected source for the period being tested. Representative conditions exclude periods of startup and shutdown. 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 such conditions represent normal operation. Upon request, you must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

* * * * *

(c) Except as specified in paragraph (c)(4) of this section, notwithstanding any other provision of this subpart, if an owner or operator of an affected source uses a flare to comply with any of the requirements of this subpart, the owner or operator shall comply with paragraphs (c)(1) through (3) of this section. The owner or operator is not required to conduct a performance test to determine percent emission reduction or outlet organic HAP or TOC concentration. If a compliance demonstration has been conducted previously for a flare, using the techniques specified in paragraphs (c)(1) through (3) of this section, that compliance demonstration may be used to satisfy the requirements of this paragraph if either no deliberate process changes have been made since the compliance demonstration, or the results of the compliance demonstration reliably demonstrate compliance despite process changes.

* * * * *

(4) For each affected source as described in § 63.480, beginning no later

than the compliance dates specified in § 63.481(n), paragraphs (c)(1) through (c)(3) of this section no longer apply and instead the owner or operator of the affected source must comply with § 63.508 for the flare.

■ 142. Amend § 63.505 by:
■ a. Revising and republishing paragraph (b); and
■ b. Revising paragraph (g)(2)(ii)(B) introductory text and adding paragraph (g)(2)(ii)(B)(5).

The addition, revisions, and republication read as follows:

§ 63.505 Parameter monitoring levels and excursions.

* * * * *

(b) *Establishment of parameter monitoring levels based exclusively on performance tests.* In cases where a performance test is required by this subpart, or the owner or operator of the affected source elects to do a performance test in accordance with the provisions of this subpart, and an owner or operator elects to establish a parameter monitoring level for a control, recovery, or recapture device based exclusively on parameter values measured during the performance test, the owner or operator of the affected source shall comply with the procedures in paragraphs (b)(1) through (b)(5) of this section, as applicable.

(1) [Reserved]

(2) *Back-end process operations using a control or recovery device to comply with §§ 63.493 through 63.500 and continuous front-end process vents.* During each compliance test, the appropriate parameter shall be continuously monitored during the required 1-hour runs. The monitoring level(s) shall then be established as the average of the maximum (or minimum) point values from the three test runs. The average of the maximum values shall be used when establishing a maximum level, and the average of the minimum values shall be used when establishing a minimum level.

(3) *Batch front-end process vents.* The monitoring level(s) shall be established using the procedures specified in either paragraph (b)(3)(i) or (b)(3)(ii) of this section, except as specified in paragraph (b)(5) of this section. The procedures specified in this paragraph (b)(3) may only be used if the batch emission episodes, or portions thereof, selected to be controlled were tested, and monitoring data were collected, during the entire period in which emissions were vented to the control device, as specified in § 63.490(c)(1)(i). If the owner or operator chose to test only a portion of the batch emission episode, or portion thereof, selected to be controlled, the procedures in paragraph (c) of this section shall be used.

(i) If more than one batch emission episode or more than one portion of a batch emission episode has been selected to be controlled, a single level for the batch cycle shall be calculated as follows:

(A) The average monitored parameter value shall be calculated for each batch emission episode, or portion thereof, in the batch cycle selected to be controlled. The average shall be based on all values measured during the required performance test.

(B) If the level to be established is a maximum operating parameter, the level shall be defined as the minimum of the average parameter values of the batch emission episodes, or portions thereof, in the batch cycle selected to be controlled (*i.e.,* identify the emission episode, or portion thereof, which requires the lowest parameter value in order to assure compliance. The average parameter value that is necessary to assure compliance for that emission episode, or portion thereof, shall be the level for all emission episodes, or portions thereof, in the batch cycle, that are selected to be controlled).

(C) If the level to be established is a minimum operating parameter, the level shall be defined as the maximum of the average parameter values of the batch emission episodes, or portions thereof, in the batch cycle selected to be controlled (*i.e.,* identify the emission episode, or portion thereof, which requires the highest parameter value in order to assure compliance. The average parameter value that is necessary to assure compliance for that emission episode, or portion thereof, shall be the level for all emission episodes, or portions thereof, in the batch cycle, that are selected to be controlled).

(D) Alternatively, an average monitored parameter value shall be calculated for the entire batch cycle based on all values measured during each batch emission episode, or portion thereof, selected to be controlled.

(ii) Instead of establishing a single level for the batch cycle, as described in paragraph (b)(3)(i) of this section, an owner or operator may establish separate levels for each batch emission episode, or portion thereof, selected to be controlled. Each level shall be determined as specified in paragraph (b)(3)(i)(A) of this section.

(iii) The batch cycle shall be defined in the Notification of Compliance Status, as specified in § 63.506(e)(5). The definition shall include an identification of each batch emission episode and the information required to determine parameter monitoring compliance for partial batch cycles (*i.e.,* when part of a batch cycle is accomplished during two different operating days).

(4) *Aggregate batch vent streams.* For aggregate batch vent streams, except as specified in paragraph (b)(5) of this section, the monitoring level shall be established in accordance with paragraph (b)(2) of this section.

(5) *Batch front-end process vents and aggregate batch vent streams testing for dioxins and furans.* During each compliance test using the procedures specified in § 63.490(g), the appropriate parameter shall be continuously monitored during the required test runs. The monitoring level(s) shall then be established as the average of the maximum (or minimum) point values from the three test runs. The average of the maximum values shall be used when establishing a maximum level, and the average of the minimum values shall be used when establishing a minimum level.

* * * * *

(g) * * *

(2) * * *

(ii) * * *

(B) Except as specified in paragraph (g)(2)(ii)(B)(*5*) of this section, subtract the time during the periods identified in paragraphs (g)(2)(ii)(B)(*1*) through (*4*) of this section from the total amount of time determined in paragraph (g)(2)(ii)(A) of this section, to obtain the operating time used to determine if monitoring data are insufficient.

* * * * *

(*5*) On and after July 15, 2027, paragraphs (g)(2)(ii)(B)(*1*) through (*4*) of this section no longer apply.

* * * * *

■ 143. Amend § 63.506 by:
■ a. Revising and republishing paragraph (b)(1);
■ b. Revising paragraph (e)(4)(ii)(F)(*1*);
■ c. Adding paragraph (e)(4)(ii)(F)(*6*);
■ d. Revising paragraph (e)(5) introductory text;
■ e. Revising and republishing paragraph (e)(5)(i);
■ f. Adding paragraph (e)(5)(xiii);
■ g. Revising and republishing paragraph (e)(6);
■ h. Revising paragraph (e)(7) introductory text;
■ i. Adding paragraph (e)(7)(vi);
■ j. Revising paragraph (i)(1); and
■ k. Adding paragraph (i)(3).

The additions, revisions, and republications read as follows:

§ 63.506 General recordkeeping and reporting provisions.

* * * * *

(b) * * *

(1) *Malfunction records.* Each owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment), air pollution control equipment, or monitoring equipment. Each owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.483(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(i) *Records of start-up, shutdown, and malfunction.* Except as specified in paragraph (b)(1)(i)(D) of this section, the owner or operator shall keep the records specified in paragraphs (b)(1)(i)(A) through (b)(1)(i)(C) of this section.

(A) Records of the occurrence and duration of each start-up, shutdown, and malfunction of operation of process equipment or control devices or recovery devices or continuous monitoring systems used to comply with this subpart during which excess emissions occur.

(B) For each start-up, shutdown, or malfunction during which excess emissions occur, records reflecting whether the procedures specified in the affected source's start-up, shutdown, and malfunction plan were followed, and documentation of actions taken that are not consistent with the plan. For example, if a start-up, shutdown, and malfunction plan includes procedures for routing a control device to a backup control device, records shall be kept of whether the plan was followed. These records may take the form of a "checklist," or other form of recordkeeping that confirms conformance with the start-up, shutdown, and malfunction plan for the event.

(C) Records specified in paragraphs (b)(1)(i)(A) and (B) of this section are not required if they pertain solely to Group 2 emission points that are not included in an emissions average.

(D) On and after July 15, 2027, paragraphs (b)(1)(i)(A) through (b)(1)(i)(C) no longer apply; however, for historical compliance purposes, a copy of these records must be retained and available on-site for five years after July 15, 2027.

(ii) *Reports of start-up, shutdown, and malfunction.* For the purposes of this subpart, the semiannual start-up, shutdown, and malfunction reports shall be submitted on the same schedule as the Periodic Reports required under paragraph (e)(6) of this section instead of the schedule specified in § 63.10(d)(5)(i). The reports shall include the information specified in § 63.10(d)(5)(i). On and after July 15, 2027, this paragraph no longer applies.

* * * * *

(e) * * *

(4) * * *

(ii) * * *

(F) * * *

(*1*) The required documentation shall include the values of the parameters used to determine whether the emission point is Group 1 or Group 2. Except as specified in paragraph (e)(4)(ii)(F)(*6*) of this section, where a TRE index value is used for continuous front-end process vent group determination, the estimated or measured values of the parameters used in the TRE equation in § 63.115(d) and the resulting TRE index value shall be submitted.

* * * * *

(*6*) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), that last sentence of paragraph (e)(4)(ii)(F)(*1*) of this section no longer applies.

* * * * *

(5) *Notification of Compliance Status.* For existing and new affected sources, a Notification of Compliance Status shall be submitted. For equipment leaks subject to § 63.502, the owner or operator shall submit the information required in § 63.182(c) in the Notification of Compliance Status within 150 days after the first applicable compliance date for equipment leaks in the affected source, and an update shall be provided in the first Periodic Report that is due at least 150 days after each subsequent applicable compliance date for equipment leaks in the affected source. For all other emission points, including heat exchange systems, the Notification of Compliance Status shall contain the information listed in paragraphs (e)(5)(i) through (xiii) of this section, as applicable, and shall be submitted no later than 150 days after the compliance dates specified in this subpart.

(i) The results of any emission point group determinations, process section applicability determinations, performance tests, inspections, any other information used to demonstrate compliance, values of monitored parameters established during performance tests, and any other information required to be included in the Notification of Compliance Status under §§ 63.122 and 63.484 for storage vessels, § 63.117 for continuous front-end process vents, § 63.492 for batch front-end process vents, § 63.499 for back-end process operations, § 63.146 for process wastewater, and § 63.503 for emission points included in an emissions average. In addition, the owner or operator of an affected source shall comply with paragraphs (e)(5)(i)(A) and (B) of this section.

(A) For performance tests, group determinations, and process section applicability determinations that are based on measurements, the Notification of Compliance Status shall include one complete test report, except as specified in paragraph (e)(5)(i)(B) of this section, for each test method used for a particular kind of emission point. For additional tests performed for the same kind of emission point using the same method, the results and any other information, from the test report, that is requested on a case-by-case basis by the Administrator shall be submitted, but a complete test report is not required.

(B) If the performance test results have been submitted electronically via the Compliance and Emissions Data Reporting Interface (CEDRI) in accordance with paragraph (i) of this section, the unit(s) tested, the pollutant(s) tested, and the date that such performance test was conducted may be submitted in the Notification of Compliance Status in lieu of the performance test report. The performance test results must be submitted to CEDRI by the date the Notification of Compliance Status is submitted. A complete test report shall include a brief process description, 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.

* * * * *

(xiii) For flares subject to the requirements in § 63.508, owners and operators must also submit the information in this paragraph in a supplement to the Notification of Compliance Status within 150 days after the first applicable compliance date for flare monitoring. The supplement to the Notification of Compliance Status must include 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 initial visible emissions demonstration required by § 63.670(h), as applicable;

and all periods during the compliance determination when the pilot flame or flare flame is absent.

(6) *Periodic Reports.* For existing and new affected sources, the owner or operator shall submit Periodic Reports as specified in paragraphs (e)(6)(i) through (xiii) of this section. In addition, for equipment leaks subject to § 63.502, the owner or operator shall submit the information specified in § 63.182(d) under the conditions listed in § 63.182(d) as part of the Periodic Report required by this paragraph (e)(6), and for heat exchange systems subject to § 63.502(n), the owner or operator shall submit the information specified in § 63.104(f)(2) as part of the Periodic Report required by this paragraph (e)(6). Section § 63.505 shall govern the use of monitoring data to determine compliance for Group 1 emission points and for Group 1 and Group 2 emission points included in emissions averages with the following exception: As discussed in § 63.484(k), for storage vessels to which the provisions of § 63.505 do not apply, as specified in the monitoring plan required by § 63.120(d)(2), the owner or operator is required to comply with the requirements set out in the monitoring plan, and monitoring records may be used to determine compliance. On and after July 15, 2027 or once the reporting template for this subpart has been available on the CEDRI website for 1 year, whichever date is later, owners and operators must submit all subsequent reports following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Polymers and Resins Sector Lead. Owners and operators must use the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports under § 63.9(i) and § 63.10(a), the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(i) Except as specified in paragraphs (e)(6)(xi) and (xii) of this section, a report containing the information in paragraph (e)(6)(ii) of this section or paragraphs (e)(6)(iii) through (x) and (xiii) of this section, as appropriate, shall be submitted semiannually no later than 60 days after the end of each 6-month period. The first report shall be submitted no later than 240 days after the date the Notification of Compliance Status is due and shall cover the 6-month period beginning on the date the Notification of Compliance Status is due. All periodic reports must contain the company name and address (including county), as well as the beginning and ending dates of the reporting period.

(ii) If none of the compliance exceptions in paragraphs (e)(6)(iii) through (ix) or (xiii) of this section occurred during the 6-month period, the Periodic Report required by paragraph (e)(6)(i) of this section shall be a statement that there were no compliance exceptions as described in this paragraph for the 6-month period covered by that report and that none of the activities specified in paragraphs (e)(6)(iii) through (ix) or (xiii) of this section occurred during the 6-month period covered by that report.

For an owner or operator of an affected source complying with the provisions of §§ 63.484 through 63.501 for any emission point, Periodic Reports shall include:

(A) All information specified in § 63.122(a)(4) for storage vessels, §§ 63.117(a)(3) and 63.118(f) and 63.485(s)(5) for continuous front-end process vents, § 63.492 for batch front-end process vents and aggregate batch vent streams, § 63.499 for back-end process operations, § 63.104(f)(2) for heat exchange systems, and §§ 63.146(c) through 63.146(g) for process wastewater.

(B) The daily average values or batch cycle daily average values of monitored parameters for all excursions, as defined in § 63.505(g) and § 63.505(h). For excursions caused by lack of monitoring data, the start date and time and duration (in hours) of periods when monitoring data were not collected shall be specified.

(C) For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), for each excursion that is not an excused excursion, the report must include the date of the excursion, a list of the affected sources or equipment, an estimate of the quantity in pounds of each regulated pollutant emitted over any emission limit, a description of the method used to estimate the emissions, the cause of the excursion (including unknown cause, if applicable), as applicable, and the corrective action taken.

(D) The information in paragraphs (e)(6)(iii)(D)(*1*) through (e)(6)(iii)(D)(*5*) of this section, as applicable:

(*1*) Any supplements to the Emissions Averaging Plan, as required in paragraph (e)(4)(iii) of this section;

(*2*) Notification if a process change is made such that the group status of any emission point changes from Group 2 to Group 1. The owner or operator is not required to submit a notification of a process change if that process change caused the group status of an emission point to change from Group 1 to Group 2. However, until the owner or operator notifies the Administrator that the group status of an emission point has changed from Group 1 to Group 2, the owner or operator is required to continue to comply with the Group 1 requirements for that emission point. This notification may be submitted at any time.

(*3*) Notification if one or more emission points (other than equipment leaks) or one or more EPPU is added to an affected source. The owner or operator shall submit the information contained in paragraphs (e)(6)(iii)(D)(*3*)(*i*) through (e)(6)(iii)(D)(*3*)(*ii*) of this section.

(*i*) A description of the addition to the affected source; and

(*ii*) Notification of the group status of the additional emission point or all emission points in the EPPU.

(*4*) Notification if a standard operating procedure, as defined in § 63.500(a)(2), is changed and the change has the potential for increasing the concentration of carbon disulfide in the crumb dryer exhaust. This notification shall also include a summary of the test results of the carbon disulfide concentration resulting from the new standard operating procedure. The results of the performance test must be submitted according to paragraph (i) of this section by the date the Periodic Report is submitted.

(*5*) For process wastewater streams sent for treatment pursuant to § 63.132(g), reports of changes in the identity of the treatment facility or transferee.

(E) The start date, start time, duration in hours, 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 § 63.483(a), including actions taken to correct a malfunction.

(iv) For each batch front-end process vent with a batch mass input limitation, every second Periodic Report shall include the mass of HAP or material input to the batch unit operation during the 12-month period covered by the preceding and current Periodic Reports, and a statement of whether the batch front-end process vent was in or out of compliance with the batch mass input limitation.

(v) Except as specified in paragraph (i) of this section, if any performance tests are reported in a Periodic Report, the following information shall be included:

(A) One complete test report shall be submitted for each test method used for a particular kind of emission point tested. A complete test report shall contain the information specified in paragraph (e)(5)(i)(B) of this section.

(B) For additional tests performed for the same kind of emission point using the same method, results and any other information, pertaining to the performance test, that is requested on a case-by-case basis by the Administrator shall be submitted, but a complete test report is not required.

(vi) Notification of a change in the primary product of an EPPU, in accordance with the provisions in § 63.480(f). This includes a change in primary product from one elastomer product to either another elastomer product or to a non-elastomer product.

(vii) The results for each change made to a predominant use determination made under § 63.480(g) for a storage vessel that is assigned to an affected source subject to this subpart after the change.

(viii) The results for each change made to a predominant use determination made under § 63.480(h) for recovery operations equipment assigned to an affected source subject to this subpart after the change.

(ix) An owner or operator complying with paragraph (h)(1) of this section shall notify the Administrator of the election to comply with paragraph (h)(1) of this section as part of the Periodic Report or as part of the Notification of Compliance Status as specified in paragraph (e)(5)(xi) of this section.

(x) An owner or operator electing not to retain daily average or batch cycle daily average values under paragraph (h)(2) of this section shall notify the Administrator as specified in paragraph (h)(2)(i) of this section.

(xi) The owner or operator of an affected source shall submit quarterly reports for all emission points included in an emissions average as specified in paragraphs (e)(6)(xi)(A) through (C) of this section.

(A) The quarterly reports shall be submitted no later than 60 days after the end of each quarter. The first report shall be submitted with the Notification of Compliance Status no later than 150 days after the compliance date.

(B) The quarterly reports shall include the information specified in paragraphs (e)(6)(xi)(B)(*1*) through (e)(6)(xi)(B)(*7*) of this section for all emission points included in an emissions average.

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

(*2*) A demonstration that debits calculated for the quarter are not more than 1.30 times the credits calculated for the quarter, as required under § 63.503(e)(4);

(*3*) The values of any inputs to the debit and credit equations in § 63.503(g) and (h) that change from month to month during the quarter or that have changed since the previous quarter;

(*4*) Except as specified in paragraph (i) of this section, results of any performance tests conducted during the reporting period including one complete report for each test method used for a particular kind of emission point as described in paragraph (e)(6)(v) of this section. If the performance test was submitted to CEDRI, include the unit(s) tested, the pollutant(s) tested, and the date of the performance test(s) in the quarterly report. The performance test results must be submitted to CEDRI by the date the quarterly report is due;

(*5*) Reports of daily average values or batch cycle daily averages of monitored parameters for excursions as defined in § 63.505(g) or (h) and the date of the excursion;

(*6*) For excursions caused by lack of monitoring data, the start date and time and duration in hours of periods when monitoring data were not collected shall be specified; and

(*7*) Any other information the affected source is required to report under the operating permit or Emissions Averaging Plan for the affected source.

(C) Every fourth quarterly report shall include the following:

(*1*) A demonstration that annual credits are greater than or equal to annual debits as required by § 63.503(e)(3); and

(*2*) A certification of compliance with all the emissions averaging provisions in § 63.503.

(xii) The owner or operator of an affected source shall submit quarterly reports for particular emission points and process sections not included in an emissions average as specified in paragraphs (e)(6)(xii)(A) through (D) of this section.

(A) The owner or operator of an affected source shall submit quarterly reports for a period of 1 year for an emission point or process section that is not included in an emissions average if:

(*1*) A control or recovery device for a particular emission point or process section has more excursions, as defined in § 63.505(g) or (h), than the number of excused excursions allowed under § 63.505(i) for a semiannual reporting period; or

(*2*) The Administrator requests that the owner or operator submit quarterly reports for the emission point or process section.

(B) The quarterly reports shall include all information specified in paragraphs (e)(6)(iii) through (ix) of this section, as applicable to the emission point or process section for which quarterly reporting is required under paragraph (e)(6)(xii)(A) of this section. Information applicable to other emission points within the affected source shall be submitted in the semiannual reports required under paragraph (e)(6)(i) of this section.

(C) Quarterly reports shall be submitted no later than 60 days after the end of each quarter.

(D) After quarterly reports have been submitted for an emission point for 1 year without more excursions occurring (during that year) than the number of excused excursions allowed under § 63.505(i), the owner or operator may return to semiannual reporting for the emission point or process section.

(xiii) The information specified in § 63.108(l)(2).

(7) *Other reports.* Other reports shall be submitted as specified in paragraphs (e)(7)(i) through (vi) of this section.

* * * * *

(vi) For fenceline monitoring systems subject to § 63.184, each owner or operator must submit the Fenceline Monitoring Reports required by § 63.182(e) on a quarterly basis following the procedures specified in § 63.182(e).

* * * * *

(i)(1) Except as specified in paragraph (i)(3) of this section, as of January 1, 2012, and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to EPA's Central Data Exchange by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/erttool.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.

* * * * *

(3) Beginning no later than July 15, 2024, owners and operators must submit performance test reports in accordance with this paragraph. Unless otherwise specified in this subpart, within 60 days after the date of completing each performance test required by this

subpart, owners and operators must submit the results of the performance test following the procedures specified in § 63.9(k). Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, owners and operators may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

■ 144. Amend § 63.507 by revising paragraph (c) introductory text and adding paragraphs (c)(5) and (6) to read as follows:

§ 63.507 Implementation and enforcement.

* * * * *

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (6) of this section.

* * * * *

(5) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

(6) Approval of an extension request under § 63.6(i)(4)(ii).

■ 145. Add § 63.508 to read as follows:

§ 63.508 Flare requirements.

(a) For any flare that is used to reduce organic HAP emissions from an EPPU, the owner or operator may elect to comply with the requirements in this section in lieu of the requirements of § 63.11(b) and the requirements referenced therein. The owner or operator may also elect to comply with the requirements in this section pursuant to the overlap provisions provided in § 63.481(k)(2). However, beginning no later than the compliance dates specified in § 63.481(n), the provisions specified in paragraphs (a)(1) through (32) of this section no longer apply. Instead, if an owner or operator reduces organic HAP emissions from an EPPU by venting emissions through a closed-vent system to a steam-assisted, air-assisted, or non-assisted flare, then the owner or operator must meet the applicable requirements for flares as specified in §§ 63.670 and 63.671, including the provisions in tables 12 and 13 to subpart CC of this part, except as specified in paragraph (b) of this section. This requirement also applies to any flare using fuel gas from a fuel gas system, of which 50 percent or more of the fuel gas is derived from a EPPU, as determined on an annual average basis. For purposes of compliance with this paragraph, the following terms are defined in § 63.641 of subpart CC of this part: Assist air, assist steam, center steam, combustion zone, combustion zone gas, flare, flare purge gas, flare supplemental gas, flare sweep gas, flare vent gas, lower steam, net heating value, perimeter assist air, pilot gas, premix assist air, total steam, and upper steam.

(1) §§ 63.487(a)(1)(i) and (b)(1)(i);

(2) § 63.489(b)(2);

(3) § 63.490(a)(1);

(4) §§ 63.491(b)(3)(i) through (b)(3)(iii);

(5) § 63.494(d);

(6) § 63.496(b)(7)(i)(A);

(7) § 63.497(a)(2);

(8) § 63.498(d)(5)(ii)(E);

(9) § 63.502(k)(1);

(10) §§ 63.504(c)(1) through (c)(3);

(11) § 63.107(h)(9)(i) related to criteria in § 63.11(b);

(12) § 63.113(a)(1);

(13) § 63.114(a)(2);

(14) §§ 63.116(a)(1) through (a)(3);

(15) §§ 63.117(a)(5)(i) through (a)(5)(iii);

(16) § 63.118(f)(5);

(17) The last sentence in § 63.119(e)(1);

(18) §§ 63.120(e)(1) through (e)(6);

(19) §§ 63.122(c)(2) and (g)(3);

(20) § 63.126(b)(2)(i);

(21) § 63.127(a)(2);

(22) §§ 63.128(b)(1) through (b)(3);

(23) §§ 63.129(a)(5)(i) through (a)(5)(iii);

(24) §§ 63.130(a)(2)(i), (c), and (d)(5);

(25) §§ 63.139(c)(3) and (d)(3);

(26) §§ 63.145(j)(1) through (j)(3);

(27) §§ 63.146(b)(7)(i)(A) through (b)(7)(i)(C);

(28) § 63.147(d)(1);

(29) §§ 63.172(d);

(30) §§ 63.180(e)(1) through (e)(3);

(31) § 63.181(g)(1)(iii); and

(32) The phrase "including periods when a flare pilot light system does not have a flame" in § 63.181(g)(2)(i).

(b) The exceptions specified in paragraphs (b) through (o) of § 63.108 apply, except as specified in paragraphs (b)(1) through (5) of this section.

(1) Where the term "chemical manufacturing process unit" is used, the term "EPPU" applies instead for the purposes of this subpart.

(2) Where the reference "§ 63.100(k)(10)" is used, the reference § 63.481(n) applies instead for the purposes of this subpart.

(3) Where the phrase "Hazardous Organic Chemical Manufacturing" is used, the phrase "Polymers and Resins" applies instead for the purposes of this subpart.

(4) Where the reference "§ 63.152(b)(7) of subpart G of this part" is used, the reference "§ 63.506(e)(5)(xiii)" applies instead for the purposes of this subpart.

(5) Section 63.108(i) does not apply.

■ 146. Add § 63.509 to read as follows:

§ 63.509 Procedures for determining whether process vents, storage vessels, or wastewater are in chloroprene service.

This section applies beginning no later than the compliance dates specified in § 63.481(o). To determine if process vents, storage vessels, or wastewater in a process at affected sources producing neoprene are in chloroprene service, as defined in § 63.482, owners and operators must comply with the requirements in paragraphs (a) through (c) of this section, as applicable.

(a) For each continuous front-end process vent, each batch front-end process vent, and each back-end process vent in a process at affected sources producing neoprene, owners and operators must measure the flow rate and concentration of chloroprene of each process vent as specified in paragraphs (a)(1) through (5) of this section.

(1) Measurements must be made prior to any dilution of the vent streams.

(2) Measurements may be made on the combined vent streams at an elastomer product process unit or for each separate vent stream.

(3) The sampling site shall be after the last recovery device (if any recovery devices are present) but prior to the inlet of any control device that is present and prior to release to the atmosphere. Method 1 or 1A of appendix A–1 to 40 CFR part 60, as appropriate, must be used for the selection of the sampling sites. For vents smaller than 0.10 meter in diameter, sample at one point at the center of the duct.

(4) The gas volumetric flow rate must be determined using Method 2, 2A, 2C, 2D, 2F, or 2G of appendices A–1 and A–2 to 40 CFR part 60, as appropriate.

(5) Except as specified in paragraph (a)(6) of this section, the concentration of chloroprene must be determined using Method 18 of appendix A–6 to 40 CFR part 60 or Method 320 of appendix A to this part.

(6) You may elect to use ASTM D6348–12 (Reapproved 2020) (incorporated by reference, § 63.14) in lieu of Method 320 of appendix A to this part as specified in paragraph (a)(5) of this section. To comply with this

paragraph, Annexes Al through A8 to ASTM D6348–12 (Reapproved 2020) are mandatory; the percent (%) R must be determined for each target analyte using Equation A5.5 of ASTM D6348–12 (Reapproved 2020) Annex A5 (Analyte Spiking Technique); and in order for the test data to be acceptable for a compound, the %R must be $70\% \geq R \leq 130\%$. If the %R value does not meet this criterion for a target compound, then 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:

Equation 1 to Paragraph (a)(6)

$$\text{Reported Results} = (\text{Measured Concentration in the Stack} \times 100)/\%R.$$

(b) For storage vessels in a process at affected sources producing neoprene, owners and operators must determine the concentration of chloroprene of the fluid stored in the storage vessels by complying with the requirements in paragraph (b)(1) or (2) of this section.

(1) The owner or operator must measure concentration of chloroprene of the fluid stored in the storage vessel using Method 624.1 of appendix A to 40 CFR part 136 or preparation by Method SW–846–5030B (incorporated by reference, see § 63.14) and analysis by Method SW–846–8260D (incorporated by reference, see § 63.14). If owners and operators collect a sample from a pressure vessel, then the owner or operator must maintain the sample under pressure both during and following sampling.

(2) Unless specified by the Administrator, the owner or operator may calculate the concentration of chloroprene of the fluid stored in the storage vessels if information specific to the fluid stored is available. Information specific to the fluid stored includes concentration data from safety data sheets.

(c) For wastewater in a process at affected sources producing neoprene, owners and operators must measure concentration of chloroprene of the fluid stored in the storage vessel using Method 624.1 of appendix A to 40 CFR part 136, or preparation by Method SW–846–5030B (incorporated by reference, see § 63.14) and analysis by Method SW–846–8260D (incorporated by reference, see § 63.14). If owners and operators collect a sample from a pressure vessel, then the owner or operator must maintain the sample under pressure both during and following sampling.

■ 147. Add § 63.510 to read as follows:

§ 63.510 Process vents, storage vessels, and wastewater that are in chloroprene service—procedures to determine compliance.

This section applies beginning no later than the compliance dates specified in § 63.481(o). In order to demonstrate compliance with the emission limits and work practice standards specified in § 63.485(y) (for continuous front-end process vents in chloroprene service), § 63.487(j) (for batch front-end process vents in chloroprene service), § 63.494(a)(7) (for back-end process vents in chloroprene service), § 63.484(u) (for storage vessels in chloroprene service), and § 63.501(a)(10)(iv) (for wastewater in chloroprene service), owners and operators must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) For initial compliance, owners and operators must comply with paragraphs (a)(1) through (4) of this section, as applicable.

(1) [Reserved]

(2) If an owner or operator chooses to reduce emissions of chloroprene by venting emissions through a closed vent system to a non-flare control device that reduces chloroprene by greater than or equal to 98 percent by weight as specified in § 63.484(u), § 63.485(y), § 63.487(j), or § 63.494(a)(7) then the owner or operator must comply with § 63.148 and paragraphs (a)(2)(i) through (viii) of this section.

(i) Conduct an initial performance test of the control device that is used to comply with the percent reduction requirement at the inlet and outlet of the control device. For purposes of compliance with this paragraph, owners and operators may not use a design evaluation. This paragraph does not apply if the conditions specified in paragraphs (a)(2)(i)(A) through (D) of this section are met for a previously-conducted measurement or performance test.

(A) No changes have been made to the process since the time of the measurement or performance test;

(B) The operating conditions and test methods used during measurement or performance test conform to the chloroprene related requirements of this subpart;

(C) The control device and process parameter values established during the previously-conducted measurement or performance test are used to demonstrate continuous compliance with the chloroprene related requirements of this subpart; and

(D) The previously-conducted measurement or performance test was completed within the last 60 months.

(ii) Conduct the performance test according to the procedures in § 63.504 and in § 63.116(c). Except as specified in § 63.509(a)(6), use Method 18 of 40 CFR part 60, appendix A–6 or Method 320 of appendix A to this part to determine the chloroprene concentration. Use Method 1 or 1A of 40 CFR part 60, appendix A–1 to select the sampling sites at each sampling location. Determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of 40 CFR part 60, appendix A–2. Use Method 4 of 40 CFR part 60, appendix A–3 to convert the volumetric flowrate to a dry basis.

(iii) Calculate the mass emission rate of chloroprene entering the control device and exiting the control device using Equations 1 and 2 to this paragraph.

Equations 1 and 2 to Paragraph (a)(2)(iii)

$$E_{,inlet} = K\, C_{,inlet}\, M\, Q_{inlet} \text{ (Eq. 1)}$$

$$E_{,outlet} = K\, C_{,outlet}\, M\, Q_{outlet} \text{ (Eq. 2)}$$

Where:

$E_{,inlet}$, $E_{,outlet}$ = Mass rate of chloroprene at the inlet and outlet of the control device, respectively, kilogram per hour.

$C_{,inlet}$, $C_{,outlet}$ = Concentration of chloroprene in the gas stream at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M = Molecular weight of chloroprene, 88.54 grams per gram-mole.

Q_{inlet}, Q_{outlet} = Flow rate of the gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

K = Constant, $2.494 \times 10 - 6$ (parts per million) − 1 (gram-mole per standard cubic meter) (kilogram per gram) (minutes per hour), where standard temperature (gram-mole per standard cubic meter) is 20 °C.

(iv) Calculate the percent reduction from the control device using equation 3 to this paragraph. An owner or operator has demonstrated initial compliance with § 63.113(j)(2) or § 63.119(a)(5)(ii) if the overall reduction of chloroprene is greater than or equal to 98 percent by weight.

Equation 3 to Paragraph (a)(2)(iv)

$$\text{Percent reduction} = (E_{,inlet} - E_{,outlet})/E_{,inlet} * 100 \text{ (Eq. 3)}$$

Where:

$E_{,inlet}$, $E_{,outlet}$ = Mass rate of chloroprene at the inlet and outlet of the control device, respectively, kilogram per hour, calculated using Equations 5 and 6 to paragraph (a)(2)(iii) of this section.

(v) If a new control device is installed, then conduct a performance test of the new device following the procedures in paragraphs (a)(2)(i) through (iv) of this section.

(vi) [Reserved]

(vii) If an owner or operator vents emissions through a closed vent system to a thermal oxidizer, then the owner or operator must establish operating parameter limits by monitoring the operating parameters specified in paragraphs (a)(2)(vii)(A) and (B) of this section during the performance test.

(A) Combustion chamber temperature. Determine the average combustion chamber temperature during the performance test as the average of the test run averages.

(B) Flue gas flow rate. Determine the average flue gas flow rate during the performance test as the average of the test run averages.

(viii) If an owner or operator vents emissions through a closed vent system to a control device other than a thermal oxidizer, then the owner or operator must notify the Administrator of the operating parameters that are planned to be monitored during the performance test prior to establishing operating parameter limits for the control device.

(3) If an owner or operator chooses to reduce emissions of chloroprene by venting emissions through a closed vent system to a non-flare control device that reduces chloroprene to less than 1 ppmv as specified in § 63.484(u), § 63.485(y), § 63.487(j), or § 63.494(a)(7) then the owner or operator must comply with § 63.148 and either paragraph (a)(3)(i) or (ii) of this section.

(i) Install an FTIR CEMS meeting the requirements of Performance Specification 15 of 40 CFR part 60, appendix B to continuously monitor the chloroprene concentration at the exit of the control device. Comply with the requirements specified in § 63.2450(j) for CEMS.

(ii) If the owner or operator does not install a CEMS under paragraph (a)(3)(i) of this section, then the owner or operator must comply with paragraphs (a)(3)(ii)(A) through (C) of this section.

(A) Conduct an initial performance test at the outlet of the control device that is used to comply with the concentration requirement.

(B) Conduct the performance test according to the procedures in § 63.504 and in § 63.116(c). Except as specified in § 63.509(a)(6), use Method 18 of 40 CFR part 60, appendix A–6 or Method 320 of appendix A to this part to determine the chloroprene concentration. If the non-flare control device is a combustion device, correct the chloroprene concentration to 3 percent oxygen according to § 63.116(c)(iii)(B), except ''TOC or organic HAP'' and ''TOC (minus methane and ethane) or organic HAP'' in the Variables Cc and Cm must be replaced with ''chloroprene''. An owner or operator has demonstrated initial compliance with § 63.484(u), § 63.485(y), § 63.487(j), or § 63.494(a)(7) if the chloroprene concentration is less than 1 ppmv.

(C) Comply with the requirements specified in paragraphs (a)(2)(v) through (viii) of this section, as applicable.

(4) If owners and operators choose to reduce emissions of chloroprene by venting emissions through a closed vent system to a non-flare control device that reduces chloroprene to less than 5 pounds per year for all combined process vents within the process as specified in § 63.113(j)(2), then the owner or operator must comply with § 63.148 and paragraphs (a)(4)(i) through (iv) of this section.

(i) Conduct an initial performance test of the control device that is used to comply with the mass emission limit requirement at the outlet of the control device.

(ii) Conduct the performance test according to the procedures in § 63.504 and in § 63.116(c). Except as specified in § 63.509(a)(6), use Method 18 of 40 CFR part 60, appendix A–6 or Method 320 of appendix A to this part to determine the chloroprene concentration. Use Method 1 or 1A of 40 CFR part 60, appendix A–1 to select the sampling site. Determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of 40 CFR part 60, appendix A–2. Use Method 4 of 40 CFR part 60, appendix A–3 to convert the volumetric flowrate to a dry basis.

(iii) Calculate the mass emission rate of chloroprene exiting the control device using Equation 2 to paragraph (a)(2)(iii) of this section. An owner or operator has demonstrated initial compliance with § 63.113(j)(2) if the chloroprene from all process vents (controlled and uncontrolled) within the process is less than 5 pounds per year when combined.

(iv) Comply with the requirements specified in paragraphs (a)(2)(v) through (viii) of this section, as applicable.

(b) For continuous compliance, owners and operators must comply with paragraphs (b)(1) through (6) of this section, as applicable.

(1) [Reserved]

(2) If you choose to reduce emissions of chloroprene by venting emissions through a closed-vent system to a non-flare control device that reduces chloroprene to less than 1 ppmv as specified in § 63.113(j)(2) or § 63.119(a)(5)(ii) of subpart G of this part, and you choose to comply with paragraph (a)(3)(i) of this section, then continuously monitor the chloroprene concentration at the exit of the control device using an FTIR CEMS meeting the requirements of Performance Specification 15 of 40 CFR part 60, appendix B and § 63.2450(j). If an owner or operator uses an FTIR CEMS, then the owner or operator does not need to conduct the performance testing required in paragraph (b)(3) of this section or the operating parameter monitoring required in paragraphs (b)(4) through (6) of this section.

(3) Conduct a performance test no later than 60 months after the previous performance test and reestablish operating parameter limits following the procedures in paragraph (a)(2) through (4) of this section. The Administrator may request a repeat performance test at any time. For purposes of compliance with this paragraph, owners and operators may not use a design evaluation.

(4) [Reserved]

(5) If an owner or operator vents emissions through a closed vent system to a thermal oxidizer, then the owner or operator must comply with § 63.148, and the owner or operator must meet the operating parameter limits specified in paragraphs (b)(5)(i) and (ii) of this section and the requirements in paragraph (b)(5)(iii) of this section.

(i) Minimum combustion chamber temperature, equal to the average combustion chamber temperature measured during the most recent performance test. Determine combustion chamber temperature with a temperature sensor with a minimum accuracy of at least ±1 percent over the normal range of temperature measured, expressed in degrees Celsius, or 2.8 degrees Celsius, whichever is greater. Compliance with the minimum combustion chamber temperature operating limit must be determined continuously on a 1-hour block basis.

(ii) Maximum flue gas flow rate, equal to the average flue gas flow rate measured during the most recent performance test. Determine flue gas flow rate with a flow sensor with a minimum 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. Compliance with the maximum flue gas flow rate operating limit must be determined continuously on a 1-hour block basis.

(iii) The owner or operator must maintain the thermal oxidizer in accordance with good combustion practices that ensure proper combustion. Good combustion practices include, but are not limited to, proper burner maintenance, proper burner alignment, proper fuel to air distribution and mixing, routine inspection, and preventative maintenance.

(6) If an owner or operator vents emissions through a closed vent system to a control device other than a thermal oxidizer, then the owner or operator must comply with § 63.148, and the owner or operator must monitor the operating parameters identified in paragraph (a)(2)(viii) of this section and meet the established operating parameter limits to ensure continuous compliance. The frequency of monitoring and averaging time will be determined based upon the information provided to the Administrator.

■ 148. Amend Table 1 to Subpart U by revising entry "§ 63.6(e)(1)(i)", adding entry "§ 63.7(a)(4)", revising entries "§ 63.8(c)(1)(i)", "§ 63.8(c)(1)(iii)", "§ 63.9(k)" and "63.10(d)(5)(i)", removing entry "§ 63.10(d)(5)(ii)", revising entry "§ 63.11", and removing note a to read as follows:

TABLE 1 TO SUBPART U OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART U AFFECTED SOURCES

Reference	Applies to subpart U	Explanation
*	*	* * * * *
§ 63.6(e)(1)(i)	No	See § 63.483(a) for general duty requirement. Any cross reference to § 63.6(e)(1)(i) in any other general provision incorporated by reference shall be treated as a cross reference to § 63.483(a).
*	*	* * * * *
§ 63.6(i)(4)(ii)	No; except yes for affected sources producing neoprene.	
*	*	* * * * *
§ 63.7(a)(4)	Yes.	
§ 63.8(a)(3)	No	[Reserved.].
§ 63.8(a)(4)	Yes, except for flares subject to § 63.508.	
§ 63.8(b)(1)	Yes.	
§ 63.8(b)(2)	No	Subpart U specifies locations to conduct monitoring.
§ 63.8(b)(3)	Yes.	
*	*	* * * * *
§ 63.8(c)(1)(i)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	
*	*	* * * * *
§ 63.8(c)(1)(iii)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.	
*	*	* * * * *
§ 63.9(k)	Yes.	
*	*	* * * * *
63.10(d)(5)	No.	
*	*	* * * * *
§ 63.11	Yes	Except for flares subject to § 63.508, § 63.11(b) specifies requirements for flares used to comply with provisions of this subpart. § 63.504(c) contains the requirements to conduct compliance demonstrations for flares subject to this subpart that are not subject to § 63.508. § 63.11(c), (d), and (e) specifies requirements for an alternative work practice for equipment leaks.
*	*	* * * * *

■ 149. Revise table 6 to subpart U to read as follows:

TABLE 6 TO SUBPART U OF PART 63—GROUP 1 BATCH FRONT-END PROCESS VENTS AND AGGREGATE BATCH VENT STREAMS—MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS

Control/recovery device	Parameter to be monitored	Recordkeeping and reporting requirements for monitored parameters
Thermal incinerators other than those used for vents in chloroprene service.	Firebox temperature[a]	1. Continuous records as specified in § 63.491(e)(1).[b] 2. Record and report the average firebox temperature measured during the performance test—NCS.[c]

TABLE 6 TO SUBPART U OF PART 63—GROUP 1 BATCH FRONT-END PROCESS VENTS AND AGGREGATE BATCH VENT STREAMS—MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS—Continued

Control/recovery device	Parameter to be monitored	Recordkeeping and reporting requirements for monitored parameters
		3. Record the batch cycle daily average firebox temperature as specified in § 63.491(e)(2). 4. Report all batch cycle daily average temperatures that are below the minimum operating value established in the NCS or operating permit and all instances when monitoring data are not collected—PR.[d][e]
Thermal oxidizers used for vents in chloroprene service.	a. Combustion chamber temperature	1. Continuous records as specified in § 63.491(e)(1).[b] 2. Record and report the average firebox temperature measured during the performance test—NCS.[c] 3. Record the 1-hour block average firebox temperature as specified in § 63.510(b)(5)(i). 4. Report all 1-hour block average temperatures that are below the minimum operating value established in the NCS or operating permit and all instances when monitoring data are not collected—PR.[d][e]
	b. Flue gas flow rate	1. Continuous records as specified in § 63.491(e)(1).[b] 2. Record and report the average flue gas flow rate measured during the performance test—NCS.[c] 3. Record the 1-hour block average flue gas flow rate as specified in § 63.510(b)(5)(ii). 4. Report all 1-hour block average flow rates that are above the maximum operating value established in the NCS or operating permit and all instances when monitoring data are not collected—PR.[d][e]
Catalytic incinerator	Temperature upstream and downstream of the catalyst bed.	1. Continuous records as specified in § 63.491(e)(1).[b] 2. Record and report the average upstream and downstream temperatures and the average temperature difference across the catalyst bed measured during the performance test—NCS.[c] 3. Record the batch cycle daily average upstream temperature and temperature difference across catalyst bed as specified in § 63.491(e)(2). 4. Report all batch cycle daily average upstream temperatures that are below the minimum upstream value established in the NCS or operating permit—PR.[d][e] 5. Reporting all batch cycle daily average temperature differences across the catalyst bed that are below the minimum difference established in the NCS or operating permit—PR.[d][e] 6. Report all instances when monitoring data are not collected.
Boiler or process heater with a design heat input capacity less than 44 megawatts and where the batch front—end process vents or aggregate batch vent streams are "not" introduced with or used as the primary fuel.	Firebox temperature[a]	1. Continuous records as specified in § 63.491(e)(1).[b] 2. Record and report the average firebox temperature measured during the performance test—NCS.[c] 3. Record the batch cycle daily average firebox temperature as specified in § 63.491(e)(2).[d] 4. Report all batch cycle daily average temperatures that are below the minimum operating value established in the NCS or operating permit and all instances when monitoring data are not collected—PR.[d][e]
Flare (if meeting the requirements of § 63.487(a)(1)(i) or (b)(1)(i)).	Presence of a flame at the pilot light	1. Hourly records of whether the monitor was continuously operating during light batch emission episodes selected for control and whether a flame was continuously present at the pilot light 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.[c] 3. Record the times and durations of all periods during batch emission episodes when all flames at the pilot light of a flare are absent or the monitor is not operating. 4. Report the times and durations of all periods during batch emission episodes selected for control when all flames at the pilot light of a flare are absent—PR.[d]
Flare (if meeting the requirements of § 63.487(a)(1)(iii) or (b)(1)(iii)).	The parameters are specified in paragraphs (b) through (o) of § 63.108 and § 63.508.	1. Records as specified in paragraph (m) of § 63.108 and § 63.508. 2. Report information as specified in in paragraph (l) of § 63.108 and § 63.508—PR.
Scrubber for halogenated batch front-end process vents or aggregate batch vent streams (Note: Controlled by a combustion device other than a flare).	a. pH of scrubber effluent, and	1. Continuous records as specified in § 63.491(e)(1).[b] 2. Record and report the average pH of the scrubber effluent measured during the performance test—NCS.[c] 3. Record the batch cycle daily average pH of the scrubber effluent as specified in § 63.491(e)(2). 4. Report all batch cycle daily average pH values of the scrubber effluent that are below the minimum operating value established in the NCS or operating permit and all instances when insufficient monitoring data are collected—PR.[d][e]
	b. Scrubber liquid and gas flow rates (§ 63.489(b)(4)(ii)).	1. Records as specified in § 63.491(e)(1).[b] 2. Record and report the scrubber liquid/gas ratio averaged over the full period of the performance test—NCS.[c] 3. Record the batch cycle daily average scrubber liquid/gas ratio as specified in § 63.491(e)(2).

Table 6 to Subpart U of Part 63—Group 1 Batch Front-End Process Vents and Aggregate Batch Vent Streams—Monitoring, Recordkeeping, and Reporting Requirements—Continued

Control/recovery device	Parameter to be monitored	Recordkeeping and reporting requirements for monitored parameters
		4. Report all batch cycle daily average scrubber liquid/gas ratios that are below the minimum value established in the NCS or operating permit and all instances when insufficient monitoring data are collected—PR.[d e]
Absorber[f]	a. Exit temperature of the absorbing liquid, and.	1. Continuous records as specified in § 63.491(e)(1).[b]
		2. Record and report the average exit temperature of the absorbing liquid measured during the performance test—NCS.[c]
		3. Record the batch cycle daily average exit temperature of the absorbing liquid as specified in § 63.491(e)(2) for each batch cycle.
		4. Report all the batch cycle daily average exit temperatures of the absorbing liquid that are above the maximum operating temperature established in the NCS or operating permit and all instances when monitoring data are not collected—PR.[d e]
	b. Exit specific gravity of the absorbing liquid	1. Continuous records as specified in § 63.491(e)(1).[b]
		2. Record and report the average exit specific gravity measured during the performance test—NCS.
		3. Record the batch cycle daily average exit specific gravity as specified in § 63.491(e)(2).
		4. Report all batch cycle daily average exit specific gravity values that are below the minimum operating value established in the NCS or operating permit and all instances when monitoring data are not collected—PR.[d e]
Condenser[f]	Exit (product side) temperature	1. Continuous records as specified in § 63.491(e)(1) [b]
		2. Record and report the average exit temperature measured during the performance test—NCS.
		3. Record the batch cycle daily average exit temperature as specified in § 63.491(e)(2).
		4. Report all batch cycle daily average exit temperatures that are above the maximum operating value established in the NCS or operating permit and all instances when monitoring data are not collected—PR.[d e]
Carbon adsorber[f]	a. Total regeneration steam flow or nitrogen flow, or pressure gauge or absolute) during carbon bed regeneration cycle(s), and.	1. Record of total regeneration steam flow or nitrogen flow, or pressure for each carbon bed regeneration cycle.
		2. Record and report the total regeneration steam flow or nitrogen flow, or pressure during each carbon bed regeneration cycle during the performance test—NCS.[c]
		3. Report all carbon bed regeneration cycles when the total regeneration steam flow or nitrogen flow, or pressure is above the maximum value established in the NCS or operating permit—PR.[d e]
	b. Temperature of the carbon bed after regeneration and within 15 minutes of completing any cooling cycle(s).	1. Record the temperature of the carbon bed after each regeneration and within 15 minutes of completing any cooling cycle(s).
		2. Record and report the temperature of the carbon bed after each regeneration and within 15 minutes of completing any cooling cycle(s) measured during the performance test—NCS.[c]
		3. Report all carbon bed regeneration cycles when the temperature of the carbon bed after regeneration, or within 15 minutes of completing any cooling cycle(s), is above the maximum value established in the NCS or operating permit—PR.[d e]
	Outlet HAP or TOC concentration	For each nonregenerative adsorber and regenerative adsorber that is regenerated offsite subject to the requirements in § 63.489(b)(10), the owner or operator must record each outlet HAP or TOC concentration measured according to §§ 63.489(b)(10)(i) and (b)(10)(ii).
	Adsorbent replacement	1. For each nonregenerative adsorber and regenerative adsorber that is regenerated offsite subject to the requirements in § 63.489(b)(10), the owner or operator must record date and time the adsorbent was last replaced.
	Breakthrough	For each nonregenerative adsorber and regenerative adsorber that is regenerated offsite subject to the requirements in § 63.489(b)(10), the owner or operator must:
		1. Record breakthrough limit and bed life established according to § 63.489(b)(10)(i).
		2. Report the date of each instance when breakthrough, as defined in § 63.101, is detected between the first and second adsorber and the adsorber is not replaced according to § 63.489(b)(10)(iii)(A)—PR.[g]
Sorbent injection	a. Sorbent injection rate	1. Continuous records as specified in § 63.491(e)(1).[b]
		2. Record and report the average sorbent injection rate measured during the performance test—NCS.[c]
		3. Record the batch cycle daily average sorbent injection rate as specified in § 63.491(e)(2).
		4. Report all batch cycle daily average sorbent injection rates that are below the minimum value established in the NCS or operating permit and all instances when insufficient monitoring data are collected—PR.[d e]
	b. Carrier gas flow rate	1. Continuous records as specified in § 63.491(e)(1).[b]
		2. Record and report the average carrier gas flow rate measured during the performance test—NCS.[c]

Table 6 to Subpart U of Part 63—Group 1 Batch Front-End Process Vents and Aggregate Batch Vent Streams—Monitoring, Recordkeeping, and Reporting Requirements—Continued

Control/recovery device	Parameter to be monitored	Recordkeeping and reporting requirements for monitored parameters
		3. Record the batch cycle daily average carrier gas flow rate as specified in § 63.491(e)(2). 4. Report all batch cycle daily average carrier gas flow rates that are below the minimum value established in the NCS or operating permit and all instances when insufficient monitoring data are collected—PR.[d][e]
All control devices	a. Diversion to the atmosphere from the control device *or*.	1. Hourly records of whether the flow indicator was operating during batch emission episodes selected for control and whether a diversion was detected at any time during the hour, as specified in § 63.491(e)(3). 2. Record and report the times of all periods during batch emission episodes selected for control when emissions are diverted through a bypass line, or the flow indicator is not operating—PR.[d] 3. For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), record and report the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of organic HAP in the gas in parts per million by volume and the resulting mass emissions of organic HAP in pounds that bypass a control device. For periods when the flow indicator is not operating, report the start date, start time, and duration in hours—PR.[d]
	b. Monthly inspections of sealed valves	1. Records that monthly inspections were performed as specified in § 63.491(e)(4)(i). 2. Record and report all monthly inspections that show that valves are in the diverting position or that a seal has been broken—PR.[d] 3. For each affected source as described in § 63.480, beginning no later than the compliance dates specified in § 63.481(n), record and report the start date, start time, duration in hours, estimate of the volume of gas in standard cubic feet, the concentration of organic HAP in the gas in parts per million by volume and the resulting mass emissions of organic HAP in pounds that bypass a control device. For periods when the flow indicator is not operating, report the start date, start time, and duration in hours—PR.[d]
Absorber, condenser, and carbon adsorber (as an alternative to the above).	Concentration level or reading indicated by an organic monitoring device at the outlet of the recovery device.	1. Continuous records as specified in § 63.491(e)(1).[b] 2. Record and report and average batch vent concentration level or reading measured during the performance test—NCS. 3. Record the batch cycle daily average concentration level or reading as specified in § 63.491(e)(2). 4. Report all batch cycle daily average concentration levels or readings that are above the maximum values established in the NCS or operating permit and all instances when monitoring data are not collected—PR.[d][e]

[a] Monitor may be installed in the firebox or in the duct work immediately downstream of the firebox before any substantial heat exchange is encountered.

[b] "Continuous records" is defined in § 63.111.

[c] NCS = Notification of Compliance Status described in § 63.506(e)(5).

[d] PR = Periodic Reports described in § 63.506(e)(6).

[e] The periodic reports shall include the duration of periods when monitoring data are not collected as specified in § 63.506(e)(6)(iii)(C).

[f] Alternatively, these devices may comply with the organic monitoring device provisions listed at the end of this table.

■ 150. Revise table 7 to subpart U to read as follows:

Table 7 to Subpart U of Part 63—Operating Parameters for Which Monitoring Levels Are Required To Be Established for Continuous and Batch Front-End Process Vents and Aggregate Batch Vent Streams

Control/recovery device	Parameters to be monitored	Established operating parameter(s)
Thermal incinerator	Firebox temperature	Minimum temperature.
Thermal oxidizers used for vents in chloroprene service.	Combustion chamber temperature	Minimum temperature.
Thermal oxidizers used for vents in chloroprene service.	Flue gas flow rate	Maximum flue gas flow rate.
Catalytic incinerator	Temperature upstream and downstream of the catalyst bed.	Minimum upstream temperature; and minimum temperature difference across the catalyst bed.
Boiler or process heater	Firebox temperature	Minimum temperature.
Scrubber for halogenated vents	pH of scrubber effluent; and scrubber liquid and gas flow rates [§ 63.489(b)(4)(ii)].	Minimum pH; and minimum liquid/gas ratio.
Absorber	Exit temperature of the absorbing liquid; and exit specific gravity of the absorbing liquid.	Maximum temperature; and maximum specific gravity.
Condenser	Exit temperature	Maximum temperature.
Carbon adsorber	Total regeneration steam flow or nitrogen flow, or pressure (gauge or absolute)[a] during carbon bed regeneration cycle; and temperature of the carbon bed after regeneration (and within 15 minutes of completing any cooling cycle(s)).	Maximum flow or pressure; and maximum temperature.

TABLE 7 TO SUBPART U OF PART 63—OPERATING PARAMETERS FOR WHICH MONITORING LEVELS ARE REQUIRED TO BE ESTABLISHED FOR CONTINUOUS AND BATCH FRONT-END PROCESS VENTS AND AGGREGATE BATCH VENT STREAMS—Continued

Control/recovery device	Parameters to be monitored	Established operating parameter(s)
Sorbent injection	Sorbent injection rate	Minimum injection rate.
Sorbent injection	Carrier gas flow rate	Minimum carrier gas flow rate.
Other devices (or as an alternate to the above)[b].	HAP concentration level or reading at outlet of device.	Maximum HAP concentration or reading.

[a] 25 to 50 mm (absolute) is a common pressure level obtained by pressure swing absorbers.
[b] Concentration is measured instead of an operating parameter.

■ 151. Amend table 9 to subpart U by adding an entry for § 63.506(e)(7)(vi) to read as follows:

TABLE 9 TO SUBPART U OF PART 63—ROUTINE REPORTS REQUIRED BY THIS SUBPART

Reference	Description of report	Due date
*	*	* * * * *
§ 63.506(e)(7)(vi)	Fenceline Monitoring Reports.	Quarterly, no later than 45 calendar days following the end of each quarterly reporting period. See § 63.182(e) of subpart H of this part for the due date for this report.

[a] There may be two versions of this report due at different times; one for equipment subject to § 63.502 and one for other emission points subject to this subpart.
[b] There will be two versions of this report due at different times; one for equipment subject to § 63.502 and one for other emission points subject to this subpart.
[c] Note that the EPPU remains subject to this subpart until the notification under § 63.480(f)(3)(i) is made.

■ 152. Add table 10 to subpart U to read as follows:

TABLE 10 TO SUBPART U OF PART 63—TOXIC EQUIVALENCY FACTORS

Dioxin and Furan Congener	Toxic equivalency factor
1,2,3,7,8-pentachlorodibenzo-p-dioxin	1
1,2,3,4,7,8-hexachlorodibenzo-p-dioxin	0.1
1,2,3,7,8,9-hexachlorodibenzo-p-dioxin	0.1
1,2,3,6,7,8-hexachlorodibenzo-p-dioxin	0.1
1,2,3,4,6,7,8-heptachlorodibenzo-p-dioxin	0.01
octachlorodibenzo-p-dioxin	0.0003
2,3,7,8-tetrachlorodibenzofuran	0.1
2,3,4,7,8-pentachlorodibenzofuran	0.3
1,2,3,7,8-pentachlorodibenzofuran	0.03
1,2,3,4,7,8-hexachlorodibenzofuran	0.1
1,2,3,6,7,8-hexachlorodibenzofuran	0.1
1,2,3,7,8,9-hexachlorodibenzofuran	0.1
2,3,4,6,7,8-hexachlorodibenzofuran	0.1
1,2,3,4,6,7,8-heptachlorodibenzofuran	0.01
1,2,3,4,7,8,9-heptachlorodibenzofuran	0.01
Octachlorodibenzofuran	0.0003

■ 153. Amend § 63.521 by adding paragraph (c) to read as follows:

§ 63.521 Compliance schedule.

* * * * *

(c) All affected sources that commenced construction or reconstruction on or before April 25, 2023, must be in compliance with the requirements in § 63.523(d), § 63.524(a)(3), (b)(3), and (c), § 63.525(a), (e), (j), (k), and (l), § 63.527(f) and (g), and § 63.528(a)(4) upon initial startup or on July 15, 2027, whichever is later. All affected sources that commenced construction or reconstruction after April 25, 2023, must be in compliance with the requirements in § 63.523(d), § 63.524(a)(3), (b)(3), and (c), § 63.525(a), (e), (j), (k), and (l), § 63.527(f) and (g), and § 63.528(a)(4) upon initial startup, or on July 15, 2024, whichever is later.

■ 154. Amend § 63.522 by:

■ a. Revising the definition of ''Affected source'';

■ b. Adding the definition of ''Dioxins and furans'',

■ c. Revising the definition of ''Equipment leaks'' and

■ d. Adding definitions of ''Heat Exchange System'', ''In organic hazardous air pollutant or in organic HAP service'' and ''Pressure relief device or valve''.

The additions and revisions read as follows:

§ 63.522 Definitions.

* * * * *

Affected source means all HAP emission points within a facility that are related to the production of BLR or WSR, including process vents, storage tanks, wastewater systems, equipment leaks, and heat exchange systems.

* * * * *

Dioxins and furans means total tetra- through octachlorinated dibenzo-p-dioxins and dibenzofurans.

* * * * *

Equipment leaks means, before July 15, 2027, emissions of hazardous air pollutants from a connector, pump, compressor, agitator, pressure relief device, sampling connection system, open-ended valve or line, or instrumentation system in organic hazardous air pollutant service. On and after July 15, 2027, equipment leaks means emissions of hazardous air pollutants from a connector, pump, compressor, agitator, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system in organic hazardous air pollutant service.

Heat Exchange System means any cooling tower system or once-through cooling water system (*e.g.,* river or pond water). A heat exchange system can include more than one heat exchanger and can include an entire recirculating or once-through cooling system.

In organic hazardous air pollutant 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's as determined according to the provisions of § 63.180(d). The provisions of § 63.180(d) also specify how to determine that a piece of equipment is not in organic HAP service.

Pressure relief device or valve means a valve, rupture disk, or similar device used only to release an unplanned, nonroutine discharge of gas from process equipment in order to avoid safety hazards or equipment damage. A pressure relief device discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause. Such devices include conventional, spring-actuated relief valves, balanced bellows relief valves, pilot-operated relief valves, rupture disks, and breaking, buckling, or shearing pin devices. Devices that are actuated either by a pressure of less than or equal to 2.5 pounds per square inch gauge or by a vacuum are not pressure relief devices.

* * * * *

■ 155. Amend § 63.523 by revising paragraph (a), and adding paragraphs (d) and (e) as follows:

§ 63.523 Standards for basic liquid resins manufacturers.

(a) Owners or operators of existing affected BLR sources shall operate sources such that the rate of emissions of hazardous air pollutants from all process vents, storage tanks, and wastewater systems combined shall not exceed 130 pounds per 1 million pounds of BLR produced, and comply with the dioxin and furans emissions limit for process vents specified in paragraph (e) of this section.

* * * * *

(d) For each existing, new, or reconstructed affected BLR source, beginning no later than the compliance dates specified in § 63.521(c), the owner or operator must comply with the requirements of § 63.104 for heat exchange systems, with the exceptions noted in paragraphs (d)(1) through (8) of this section.

(1) When the term ‘‘chemical manufacturing process unit’’ is used in § 63.104, the term ‘‘existing, new, or reconstructed affected BLR source’’ shall apply for the purposes of this subpart.

(2) When the phrase ‘‘a chemical manufacturing process unit meeting the conditions of § 63.100(b)(1) through (b)(3), except for chemical manufacturing process units meeting the condition specified in § 63.100(c)’’ is used in the first sentence of § 63.104(a), the term ‘‘an existing, new, or reconstructed affected BLR source’’ shall apply for the purposes of this subpart. When the phrase ‘‘a chemical manufacturing process unit meeting the conditions of § 63.100(b)(1) through (b)(3),’’ is used in the last sentence of § 63.104(a), the term ‘‘an existing, new, or reconstructed affected BLR source’’ shall apply for purposes of this subpart.

(3) When § 63.104 refers to table 4 to subpart F of this part or table 9 of subpart G of this part, the owner or operator is required to consider all hazardous air pollutants.

(4) When § 63.104(c)(3) specifies the monitoring plan retention requirements, and when § 6 3.104(f)(1) refers to the record retention requirements in § 63.103(c)(1) of subpart F of this part, the requirements in § 63.527(d) shall apply, for the purposes of this subpart.

(5) When § 63.104(f)(2) requires information to be reported in the Periodic Reports required by § 63.152(c), the owner or operator shall instead report the information specified in § 63.104(f)(2) in the Periodic Reports required by § 63.528(a), for the purposes of this subpart.

(6) The compliance date for heat exchange systems subject to the provisions of this section is specified in § 63.521(c).

(7) Substitute ‘‘Beginning no later than the compliance dates specified in § 63.521(c),’’ for each occurrence of ‘‘Beginning no later than the compliance dates specified in § 63.100(k)(10),’’.

(8) § 63.104(k) does not apply. Instead for each existing, new, or reconstructed affected BLR source, beginning no later than the compliance dates specified in § 63.521(c), owners and operators must not inject water into or dispose of water through any heat exchange system in an affected source if the water is considered wastewater as defined in § 63.522.

(e) For each existing, new, or reconstructed affected BLR source, beginning no later than the compliance dates specified in § 63.521(c), the owner or operator of a process vent that contains chlorine, hydrogen chloride, or any other chlorinated compound must reduce emissions of dioxins and furans (toxic equivalency basis) to a concentration of 0.054 nanograms per standard cubic meter on a dry basis corrected to 3 percent oxygen.

■ 156. Amend § 63.524 by revising paragraph (a) introductory text, adding paragraph (a)(3), revising paragraph (b) introductory text, and adding paragraphs (b)(3) and (c) as follows:

§ 63.524 Standards for wet strength resins manufacturers.

(a) In addition to the requirements specified in paragraph (c) of this section, and except as specified in paragraph (a)(3) of this section, owners or operators of existing affected WSR sources shall either:

* * * * *

(3) For each existing affected WSR source, beginning no later than the compliance dates specified in § 63.521(c), the owner or operator shall comply with both paragraphs (a)(1) and (a)(2) of this section and must reduce emissions of dioxins and furans (toxic equivalency basis) from each process vent that contains chlorine, hydrogen chloride, or any other chlorinated compound to a concentration of 0.054 nanograms per standard cubic meter on a dry basis corrected to 3 percent oxygen.

(b) In addition to the requirements specified in paragraph (c) of this section, and except as specified in paragraph (b)(3) of this section, owners or operators of new or reconstructed affected WSR sources shall either:

* * * * *

(3) For each new or reconstructed affected WSR source, beginning no later than the compliance dates specified in § 63.521(c), the owner or operator shall comply with both paragraphs (b)(1) and (2) of this section and must reduce emissions of dioxins and furans (toxic equivalency basis) from each process vent that contains chlorine, hydrogen chloride, or any other chlorinated compound to a concentration of 0.054 nanograms per standard cubic meter on a dry basis corrected to 3 percent oxygen.

(c) For each existing, new, or reconstructed affected WSR source, beginning no later than the compliance dates specified in § 63.521(c), the owner or operator shall comply with the requirements of § 63.104 for heat exchange systems, with the exceptions noted in paragraphs (d)(1) through (8) of this section.

(1) When the term ''chemical manufacturing process unit'' is used in § 63.104, the term ''existing, new, or reconstructed affected WSR source'' shall apply for the purposes of this subpart.

(2) When the phrase ''a chemical manufacturing process unit meeting the conditions of § 63.100(b)(1) through (b)(3) of this subpart, except for chemical manufacturing process units meeting the condition specified in § 63.100(c) of this subpart'' is used in the first sentence of § 63.104(a), the term ''an existing, new, or reconstructed affected WSR source'' shall apply for the purposes of this subpart. When the phrase ''a chemical manufacturing process unit meeting the conditions of § 63.100(b)(1) through (b)(3),'' is used in the last sentence of § 63.104(a), the term ''an existing, new, or reconstructed affected WSR source'' shall apply for purposes of this subpart.

(3) When § 63.104 refers to table 4 of subpart F of this part or Table 9 of subpart G of this part, the owner or operator is required to consider all hazardous air pollutants.

(4) When § 63.104(c)(3) specifies the monitoring plan retention requirements, and when § 63.104(f)(1) refers to the record retention requirements in § 63.103(c)(1), the requirements in § 63.527(d) shall apply, for the purposes of this subpart.

(5) When § 63.104(f)(2) requires information to be reported in the Periodic Reports required by § 63.152(c), the owner or operator shall instead report the information specified in § 63.104(f)(2) in the Periodic Reports required by § 63.528(a), for the purposes of this subpart.

(6) The compliance date for heat exchange systems subject to the provisions of this section is specified in § 63.521(c).

(7) Substitute ''Beginning no later than the compliance dates specified in § 63.521(c),'' for each occurrence of ''Beginning no later than the compliance dates specified in § 63.100(k)(10),

(8) § 63.104(k) of subpart F of this part does not apply. Instead for each existing, new, or reconstructed affected WSR source, beginning no later than the compliance dates specified in § 63.521(c), owners and operators must not inject water into (or dispose of water through) any heat exchange system in an affected source if the water is considered wastewater as defined in § 63.522.

■ 157. Amend § 63.525 by:
■ a. Revising paragraphs (a) and (b)(1);
■ b. Adding paragraph (d)(3);
■ c. Revising paragraphs (e) introductory text and (e)(2)(iii);
■ d. Adding paragraph (e)(3);
■ e. Revising paragraphs (f), (g), (h) introductory text, and (i); and
■ f. Adding paragraphs (j) through (m) as follows:

§ 63.525 Compliance and performance testing.

(a) The owner or operator of any existing affected BLR source shall, in order to demonstrate compliance with the applicable emission limits, determine the emission rate from all process vent, storage tank, and wastewater system emission points using the methods described below. Except as specified in paragraph (l) of this section, compliance tests shall be performed under normal operating conditions. Beginning no later than the compliance dates specified in § 63.521(c), conduct subsequent performance tests no later than 60 calendar months after the previous performance test.

(1) Except as specified in paragraph (m) of this section, the owner or operator shall use the EPA test methods from 40 CFR part 60, listed in paragraphs (a)(1) (i) through (iii) of this section, to determine emissions from process vents. Testing of process vents on equipment operating as part of a continuous process will consist of conducting three 1-hour runs. Gas stream volumetric flow rates shall be measured every 15 minutes during each 1-hour run. Organic HAP or TOC concentration shall be determined from samples collected in an integrated sample over the duration of each 1-hour test run, or from grab samples collected simultaneously with the flow rate measurements (every 15 minutes). If an integrated sample is collected for laboratory analysis, the sampling rate shall be adjusted proportionally to reflect variations in flow rate. If the flow of gaseous emissions is intermittent, determination of emissions from process vents shall be performed according to the methods specified in paragraph (e) of this section. For process vents with continuous gas streams, the emission rate used to determine compliance shall be the average emission rate of the 3 test runs. For process vents with intermittent emission streams, the calculated emission rate or the emission rate from a single test run may be used to determine compliance.

(i) Method 1 or 1A of appendix A–1 to 40 CFR part 60 as appropriate, shall be used for selection of the sampling sites if the flow measuring device is a pitot tube. A traverse shall be conducted before and after each 1-hour sampling period. No traverse is necessary when using Method 2A or 2D of appendix A–2 to 40 CFR part 60 to determine flow rate.

(ii) Method 2, 2A, 2C or 2D of appendix A–1 to part 60 of this chapter, as appropriate, shall be used for the determination of gas stream volumetric flow rate. If Method 2 or 2C is used, the velocity measurements shall be made at a single point, in conjunction with the traverse, to establish an average velocity across the stack.

(iii) Method 25A and/or Methods 18 and 25A of appendices A–6 and A–7 to 40 CFR part 60, as appropriate, must be used to determine the concentration of HAP in the streams. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method.

(iv) Initial determination of de minimis status for process vents may be made by engineering assessment, as specified in § 63.526(a)(1)(iv).

(2) Emissions from wastewater treatment systems shall be determined in accordance with the methods described in 40 CFR part 63, appendix C.

(3) Emissions from storage tanks shall be calculated in accordance with the methods specified in § 63.150(g)(3).

(b) * * *

(1) The production-based emission rate for process vents shall be calculated by dividing the average emission rate by the average production rate.

* * * * *

(d) * * *

(3) To demonstrate compliance with the process vent dioxins and furans emission limit, the owner or operator must use the procedures of paragraph (m) of this section.

(e) The owner or operator of any existing, new, or reconstructed WSR source that is subject to the emission limit for process vents, storage tanks, and wastewater systems shall demonstrate compliance by determining emissions for all process vent, storage tank, and wastewater systems emission points using the methods described in this section. The owner or operator of any existing, new, or reconstructed WSR source that is subject to the process vent dioxins and furans emission limit must demonstrate compliance by following the procedures in paragraph (e)(3) of this section. Beginning no later than the compliance dates specified in § 63.521(c), conduct subsequent performance tests no later than 60 calendar months after the previous performance test.

* * * * *

(2) * * *

* * * * *

(iii) Method 25A and/or Methods 18 and 25A of appendices A–6 and A–7 to 40 CFR part 60, as appropriate, must be used to determine the concentration of HAP in the streams. ASTM D6420–18 (incorporated by reference, see § 63.14) may also be used in lieu of Method 18, if the target compounds are all known and are all listed in Section 1.1 of ASTM D6420–18 as measurable; ASTM D6420–18 must not be used for methane and ethane; and ASTM D6420–18 may not be used as a total VOC method.

* * * * *

(3) To demonstrate compliance with the process vent dioxins and furans emission limit, the owner or operator must use the procedures of paragraph (m) of this section. Testing shall be performed for each unit operation.

(f) The owner or operator of any affected WSR source that is subject to the emissions limit for process vents, storage tanks, and wastewater systems shall calculate emissions from storage tanks in accordance with the methods specified in § 63.150(g)(3).

(g) The owner or operator of any affected WSR source that is subject to the emission limit for process vents, storage tanks, and wastewater systems shall calculate emissions from wastewater treatment systems (if applicable) in accordance with the methods described in 40 CFR part 63, appendix C.

(h) The owner or operator of any affected WSR source that is subject to the emission limit for process vents, storage tanks, and wastewater systems shall calculate the average amount of WSR product manufactured per batch, using data from performance tests or from emission calculations, as applicable, to determine the average WSR production per-batch production data for an annual period representing normal operating conditions.

* * * * *

(i) The owner or operator of any affected BLR source or any affected WSR source that is subject to the requirements of subpart H of this part must demonstrate the ability of its specific program to meet the compliance requirements therein to achieve initial compliance.

(j) For each existing, new, or reconstructed affected BLR and WSR source, beginning no later than the compliance dates specified in § 63.521(c), owners and operators of sources as defined in § 63.520 shall comply with the requirements of this subpart at all times, except during periods of nonoperation of the source (or specific portion thereof) resulting in cessation of the emissions to which this subpart applies.

(k) For each existing, new, or reconstructed affected BLR and WSR source, beginning no later than the compliance dates specified in § 63.521(c), at all times, owners and operators must operate and maintain any 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 owners and operators 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.

(l) For each existing, new, or reconstructed affected BLR and WSR source, beginning no later than the compliance dates specified in § 63.521(c), the owner or operator may not conduct performance tests during periods of malfunction. Owners and operators 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 such conditions represent normal operation. Upon request, owners and operators must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(m) Except as specified in paragraph (m)(7) of this section, to demonstrate compliance with the process vent dioxins and furans emission limit, the owner or operator must conduct a performance test using the procedures in paragraphs (m)(1) through (m)(6) of this section. Conduct subsequent performance tests no later than 60 calendar months after the previous performance test.

(1) The performance test must consist of three test runs. Collect at least 3 dry standard cubic meters of gas per test run.

(2) Use Method 1 or 1A of 40 CFR part 60, appendix A–1 to select the sampling sites at the sampling location. The sampling location must be at the outlet of the final control device.

(3) Determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of 40 CFR part 60, appendix A–2.

(4) Use Method 4 of 40 CFR part 60, appendix A–3 to convert the volumetric flowrate to a dry basis.

(5) Measure the concentration of each tetra- through octa-chlorinated dioxin and furan congener emitted using Method 23 at 40 CFR part 60, appendix A–7.

(i) For each dioxin and furan congener, multiply the congener concentration by its corresponding toxic equivalency factor specified in table 2 to this subpart. For determination of toxic equivalency, zero may be used for congeners with a concentration less than the estimated detection limit (EDL). For congeners with estimated maximum pollutant concentration (EMPC) results, if the value is less than the EDL, zero may be used. Otherwise, the EMPC value must be used in the calculation of toxic equivalency.

(ii) Sum the products calculated in accordance with paragraph (m)(5)(i) of this section to obtain the total concentration of dioxins and furans emitted in terms of toxic equivalency.

(6) The concentration of dioxins and furans shall be corrected to 3 percent oxygen. Use Method 3A of 40 CFR part 60, appendix A to determine the oxygen concentration ($\%O_{2d}$). Method 3A of 40 CFR part 60, appendix A must be run concurrently with Method 23 of 40 CFR part 60, appendix A–7. The concentration corrected to 3 percent oxygen (C_c) shall be computed using the following equation:

$$C_c = C_m\left(\frac{17.9}{20.9 - \%O_{2d}}\right)$$

Where:

C_c = Concentration of dioxins and furans corrected to 3 percent oxygen, dry basis, nanograms per standard cubic meter.

C_m = Concentration of dioxins and furans, dry basis, nanograms per standard cubic meter.

$\%O_2d$ = Concentration of oxygen, dry basis, percent by volume.

(7) An owner or operator is not required to conduct a performance test when either a boiler or process heater burning hazardous waste, or hazardous waste incinerator, is used for which the owner or operator:

(A) Has been issued a final permit under part 270 of this chapter and complies with the requirements of 40 CFR part 266, subpart H;

(B) Has certified compliance with the interim status requirements of part 266, subpart H, of this chapter;

(C) Meets the requirement specified in paragraph (g)(7)(i)(E) of this section, and has submitted a Notification of Compliance under § 63.1207(j) and complies with the requirements of subpart EEE of this part; or

(D) Meets the requirement specified in paragraph (g)(7)(i)(E) of this section, complies with subpart EEE of this part, and will submit a Notification of Compliance under § 63.1207(j) by the date the owner or operator would have been required to submit the initial performance test report for this subpart.

(E) The owner and operator may not waive performance testing pursuant to § 63.1207(d)(4) and each performance test required by § 63.1207(d) must show compliance with the dioxins and furans emission limit specified in § 63.523(e) and § 63.524(a)(3) and (b)(3), as applicable.

■ 158. Amend § 63.526 by:

■ a. Revising paragraphs (a) introductory text, (a)(2), (3) and (4);

■ b. Adding paragraph (a)(7);

■ c. Revising paragraphs (b) introductory text, (b)(1)(i), (b)(2), (3), and (4);

■ d. Adding paragraph (b)(7); and

■ e, Revising paragraphs (c) and (d).

The additions and revisions read as follows:

§ 63.526 Monitoring requirements.

(a) The owner or operator of any existing, new, or reconstructed affected BLR source shall provide evidence of continued compliance with the standard. During each compliance demonstration, maximum or minimum operating parameters, as appropriate, shall be established for processes and control devices that will indicate the source is in compliance. If the operating parameter to be established is a maximum, the value of the parameter shall be the average of the maximum values from each of the three test runs. If the operating parameter to be established is a minimum, the value of the parameter shall be the average of the minimum values from each of the three test runs. Parameter values for process vents with intermittent emission streams shall be determined as specified in paragraph (b)(1) of this section. The owner or operator shall operate processes and control devices within these parameters to ensure continued compliance with the standard. A de minimis level is specified in paragraph (a)(1) of this section. Monitoring parameters are specified for various process vent control scenarios in paragraphs (a) (2) through (7) of this section.

* * * * *

(2) For affected sources using water scrubbers, the owner or operator shall establish a minimum scrubber water flow rate as a site-specific operating parameter which must be measured and recorded every 15 minutes. The affected source will be considered to be out of compliance if the scrubber water flow rate, averaged over any continuous 24-hour period, is below the minimum value established during the most recent compliance demonstration.

(3) For affected sources using condensers, the owner or operator shall establish the maximum condenser outlet gas temperature as a site-specific operating parameter which must be measured and recorded every 15 minutes. The affected source will be considered to be out of compliance if the condenser outlet gas temperature, averaged over any continuous 24-hour period, is greater than the maximum value established during the most recent compliance demonstration.

(4) For affected sources using carbon adsorbers or having uncontrolled process vents, the owner or operator shall establish a maximum outlet HAP concentration as the site-specific operating parameter which must be measured and recorded every 15 minutes. The affected source will be considered to be out of compliance if the outlet HAP concentration, averaged over any continuous 24-hour period, is greater than the maximum value established during the most recent compliance demonstration.

* * * * *

(7) For affected sources using sorbent injection, the owner or operator shall establish both a minimum sorbent injection rate and minimum carrier gas flow rate flow rate as site-specific operating parameters which must be measured and recorded every 15 minutes. The affected source will be considered to be out of compliance if the sorbent injection rate or the carrier gas flow rate flow rate, averaged over any continuous 24-hour period, is below the minimum values established during the most recent compliance demonstration.

(b) The owner or operator of any existing, new, or reconstructed affected WSR source that is subject to the emission limit for process vents, storage tanks, and wastewater systems and/or is subject to the dioxins and furans emission limit for process vents shall provide evidence of continued compliance with the standard. As part of each compliance demonstrations for batch process vents, test data or compliance calculations shall be used to establish a maximum or minimum level of a relevant operating parameter for each unit operation. The parameter value for each unit operation shall represent the worst case value of the operating parameter from all episodes in the unit operation. The owner or operator shall operate processes and control devices within these parameters to ensure continued compliance with the standard.

(1) * * *

(i) If testing is used to demonstrate compliance, the appropriate parameter shall be monitored during all batch emission episodes in the unit operation.

* * * * *

(2) Affected sources with condensers on process vents shall establish the maximum condenser outlet gas temperature as a site-specific operating parameter, which must be measured every 15 minutes, or at least once for batch emission episodes less than 15 minutes in duration. The affected source will be considered to be out of compliance if the maximum condenser outlet gas temperature, averaged over the duration of the batch emission episode or unit operation, is greater than the value established during the most recent compliance demonstration.

(3) For affected sources using water scrubbers, the owner or operator shall establish a minimum scrubber water flow rate as a site-specific operating parameter which must be measured and recorded every 15 minutes, or at least once for batch emission episodes less than 15 minutes in duration. The affected source will be considered to be out of compliance if the scrubber water flow rate, averaged over the duration of the batch emission episode or unit operation, is below the minimum flow rate established during the most recent compliance demonstration.

(4) For affected sources using carbon adsorbers or having uncontrolled process vents, the owner or operator shall establish a maximum outlet HAP concentration as the site-specific operating parameter which must be measured and recorded every 15 minutes, or at least once for batch emission episodes of duration shorter than 15 minutes. The affected source will be considered to be out of compliance if the outlet HAP concentration, averaged over the duration of the batch emission episode or unit operation, is greater than the value established during the most recent compliance demonstration.

* * * * *

(7) For affected sources using sorbent injection, the owner or operator shall establish both a minimum sorbent injection rate and minimum carrier gas flow rate flow rate as site-specific operating parameters which must be measured and recorded every 15 minutes. The affected source will be considered to be out of compliance if the sorbent injection rate or the carrier gas flow rate flow rate, averaged over any continuous 24-hour period, is below the minimum values established during the most recent compliance demonstration.

(c) Periods of time when monitoring measurements exceed the parameter values do not constitute a violation if they occur during a startup, shutdown, or malfunction, and the facility is operated in accordance with § 63.6(e)(1). For each existing, new, or reconstructed affected BLR and WSR source, on and after July 15, 2027, this paragraph no longer applies.

(d) The owner or operator of any affected WSR source that is subject to the requirements of subpart H of this part shall meet the monitoring requirements of subpart H of this part.

■ 159. Amend § 63.527 by revising paragraphs (b), (c) introductory text and (d), and adding paragraphs (f) and (g) as follows:

§ 63.527 Recordkeeping requirements.

* * * * *

(b) The owner or operator of any affected WSR source subject to the emission limit for process vents, storage tanks, and wastewater systems and/or subject to the dioxins and furans emission limit for process vents shall keep records of values of equipment operating parameters specified to be monitored under § 63.526(b) or specified by the Administrator. The records that shall be kept are the average values of operating parameters, determined for the duration of each unit operation. Records shall be kept in accordance with the requirements of applicable paragraphs of § 63.10, as specified in the General Provisions applicability table in this subpart. The owner or operator shall keep records up-to-date and readily accessible. In the event of an excursion, the owner or operator must keep records of each 15-minute reading for the entire unit operation in which the excursion occurred.

(c) The owner or operator of any affected BLR source, as well the owner or operator of any affected WSR source that is subject to the emission limit for process vents, storage tanks, and wastewater systems, who demonstrates that certain process vents are below the de minimis cutoff for continuous monitoring specified in § 63.526(a)(1)(i), shall maintain up-to-date, readily accessible records of the following information to document that a HAP emission rate of less than one pound per year is maintained:

* * * * *

(d) The owner or operator of any affected BLR source, as well as the owner or operator of any affected WSR source subject to the leak detection and repair program specified in subpart H of this part, shall implement the recordkeeping requirements outlined therein. All records shall be retained for a period of 5 years, in accordance with the requirements of 40 CFR 63.10(b)(1).

* * * * *

(f) For each existing, new, or reconstructed affected BLR and WSR source, beginning no later than the compliance dates specified in § 63.521(c), the owner or operator of any affected BLR source, as well the owner or operator of any affected WSR source subject to the emission limit for process vents, storage tanks, and wastewater systems, must keep the records specified in paragraphs (f)(1) through (3) of this section each pressure relief device, as defined in § 63.522.

(1) The start and end time and date of each pressure release to the atmosphere.

(2) An estimate of the mass quantity in pounds of each organic HAP released.

(3) Records of any data, assumptions, and calculations used to estimate of the mass quantity of each organic HAP released during the event.

(g) For each existing, new, or reconstructed affected BLR and WSR source, beginning no later than the compliance dates specified in § 63.521(c), the owner or operator of any affected BLR source, as well the owner or operator of any affected WSR source subject to the emission limit for process vents, storage tanks, and wastewater systems, must keep the records specified in paragraphs (g)(1) through (3) of this section for each maintenance vent release. A process vent is considered a maintenance vent if the process 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.

(1) Identification of the maintenance vent and the equipment served by the maintenance vent.

(2) The date and time the maintenance vent was opened to the atmosphere.

(3) An estimate of the mass in pounds of organic HAP released during the entire atmospheric venting event.

■ 160. Revise and republish § 63.528 to read as follows:

§ 63.528 Reporting requirements.

(a) The owner or operator of any affected BLR source, as well as the owner or operator of any affected WSR source that is subject to the emission limit for process vents, storage tanks, and wastewater systems and/or is subject to the dioxins and furans emission limit for process vents, shall comply with the reporting requirements of applicable paragraphs of § 63.10, as specified in the General Provisions applicability table in this subpart. The owner or operator shall also submit to the Administrator, as part of the quarterly excess emissions and continuous monitoring system performance report and summary report required by § 63.10(e)(3), the following recorded information. On and after July 15, 2027 or once the reporting template for this subpart has been available on the CEDRI website for 1 year, whichever date is later, owners and operators must submit all subsequent reports following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Polymers and Resins Sector Lead. Owners and operators must use the appropriate electronic report template on the CEDRI website (*https://*

www.epa.gov/electronic-reporting-air-emissions/cedri) for this subpart. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports under § 63.9(i) and § 63.10(a), the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. If a report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirements in § 63.10(e)(3)(v), § 63.10(e)(3)(vi)(L), and § 63.10(e)(3)(vi)(M) to submit the date of the report and the name, title, and signature of the responsible official who is certifying the accuracy of the report.

(1) Reports of monitoring data, including 15-minute monitoring values as well as daily average values or per-unit operation average values, as applicable, of monitored parameters for all operating days or unit operations when the average values were outside the ranges established in the Notification of Compliance Status or operating permit, including reports specified in paragraph (a)(4) of this section.

(2) Reports of the duration of periods when monitoring data is not collected for each excursion caused by insufficient monitoring data, including reports specified in paragraph (a)(4) of this section. An excursion means any of the three cases listed in paragraph (a)(2)(i) or (a)(2)(ii) of this section. For a control device where multiple parameters are monitored, if one or more of the parameters meets the excursion criteria in paragraph (a)(2)(i) or (a)(2)(ii) of this section, this is considered a single excursion for the control device. In the report, include the identification of the source, start date, start time, duration in hours, and monitored parameter(s) meeting the excursion criteria.

(i) When the period of control device operation is 4 hours or greater in an operating day and monitoring data are insufficient to constitute a valid hour of data, as defined in paragraph (a)(2)(iii) of this section, for at least 75 percent of the operating hours.

(ii) When the period of control device operation is less than 4 hours in an operating day and more than one of the hours during the period of operation does not constitute a valid hour of data due to insufficient monitoring data.

(iii) Monitoring data are insufficient to constitute a valid hour of data, as used in paragraphs (a)(2)(i) and (ii) of this section, if measured values are unavailable for any of the 15-minute periods within the hour.

(3) Whenever a process change, as defined in § 63.115(e), is made that causes the emission rate from a de minimis emission point to become a process vent with an emission rate of one pound per year or greater, the owner or operator shall submit a report within 180 calendar days after the process change. The report may be submitted as part of the next summary report required under § 63.10(e)(3). The report shall include:

(i) A description of the process change; and

(ii) The results of the recalculation of the emission rate.

(4) For each existing, new, or reconstructed affected BLR and WSR source, beginning no later than the compliance dates specified in § 63.521(c), for each excursion that is not an excused excursion, the report must include a list of the affected sources or equipment, the monitored parameter, an estimate of the quantity in pounds of each regulated pollutant emitted over any emission limit, a description of the method used to estimate the emissions, the cause of the excursion (including unknown cause, if applicable), as applicable, and the corrective action taken. Include the start date, start time, and duration in hours of each excursion.

(5) For pressure relief device subject to § 63.527(f), report each pressure release to the atmosphere, including pressure relief device identification name or number, the start date, start time, and duration (in minutes) of the pressure release; and an estimate of the mass quantity in pounds of each organic HAP released.

(6) For heat exchangers subject to § 63.104 of subpart F of this part, the information specified in § 63.104(f)(2) of subpart F of this part.

(b) The owner or operator of any affected BLR source, as well as the owner or operator of any affected WSR source who is subject to the leak detection and repair program specified in subpart H of this part, shall implement the reporting requirements outlined therein. Copies of all reports shall be retained as records for a period of 5 years, in accordance with the requirements of 40 CFR 63.10(b)(1).

(c) The owner or operator of any affected BLR source, as well as the owner or operator of any affected WSR source that is subject to the emission limit for process vents, storage tanks, and wastewater systems shall include records of all monitoring parameters in the Notification of Compliance Status and summary reports required by subpart A of this part.

(d) Beginning no later than July 15, 2024, owners and operators must submit performance test reports in accordance with this paragraph. Unless otherwise specified in this subpart, within 60 days after the date of completing each performance test required by this subpart, owners and operators must submit the results of the performance test following the procedures specified in § 63.9(k). Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, owners and operators may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

■ 161. Amend § 63.529 by revising paragraph (c) introductory text, and adding paragraph (c)(5) as follows:

§ 63.529 Implementation and enforcement.

* * * * *

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (5) of this section.

* * * * *

(5) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

■ 162. Amend table 1 to subpart W by:

■ a. Revising the header row;

■ b. Revising entry "§ 63.6(e)(1)(i)";

■ c. Adding entries "§ 63.6(e)(1)(ii)", "§ 63.6(e)(1)(iii)", "63.6(e)(2)", and "63.6(e)(3)';

■ d. Revising entry "§ 63.6(g)";

■ e. Adding entry "§ 63.7(a)(4)"; and

■ f. Revising entries "§ 63.7(e)(1)", "§ 63.7(g)(1)", "§ 63.8(c)(1)(i)", "§ 63.8(c)(1)(iii)", "§ 63.9(k)", "§ 63.10(d)(2)", "§ 63.10(d)(5)" and "§ 63.10(e)(3)".

The revisions and additions read as follows:

TABLE 1 TO SUBPART W OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPART W

Reference	Applies to subpart W			Comment
	BLR	WSR	WSR equipment leak standard, and BLR equipment leak standard (40 CFR part 63, subpart H)	
*	*	*	*	* * *
§ 63.6(e)(1)(i)	See Comment			Yes, before July 15, 2027. No, beginning on and after July 15, 2027. See § 63.525(k) for general duty requirement.
§ 63.6(e)(1)(ii)	See Comment			Yes, before July 15, 2027. No, beginning on and after July 15, 2027.
§ 63.6(e)(1)(iii)	Yes	Yes	Yes.	
63.6(e)(2)	N/A	N/A	N/A	Reserved.
63.6(e)(3)	See Comment			Yes, before July 15, 2027. No, beginning on and after July 15, 2027.
*	*	*	*	* * *
§ 63.6(g)	Yes	Yes	Yes	Affected sources have the opportunity to demonstrate other alternatives to the Administrator.
*	*	*	*	* * *
§ 63.7(a)(4)	Yes	Yes	Yes.	
*	*	*	*	* * *
§ 63.7(e)(1)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.			See § 63.525(l). Subpart W also contains test methods specific to BLR and WSR sources.
*	*	*	*	* * *
§ 63.7(g)(1)	Yes	Yes	No	Subpart H specifies performance test reporting. Additionally, this subpart specifies how and when the performance test results are reported for BLR and WSR.
§ 63.8(b)(3)	Yes	Yes	Yes.	
§ 63.8(c)(1)(i)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.			
*	*	*	*	* * *
§ 63.8(c)(1)(iii)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.			
*	*	*	*	* * *
§ 63.9(k)	Yes	Yes	Yes.	
*	*	*	*	* * *
§ 63.10(d)(2)	No	No	No	This subpart and Subpart H specify performance test reporting requirements.
*	*	*	*	* * *
§ 63.10(d)(5)	Yes, before July 15, 2027. No, beginning on and after July 15, 2027.			
*	*	*	*	* * *
§ 63.10(e)(3)	Yes	Yes	No	Except that on and after July 15, 2027, the reports shall be submitted according to and in the format required by § 63.528(a).
*	*	*	*	* * *

■ 163. Add table 2 to subpart W to read as follows:

TABLE 2 TO SUBPART W OF PART 63—TOXIC EQUIVALENCY FACTORS

Dioxin and Furan Congener	Toxic equivalency factor
1,2,3,7,8-pentachlorodibenzo-p-dioxin	1
1,2,3,4,7,8-hexachlorodibenzo-p-dioxin	0.1
1,2,3,7,8,9-hexachlorodibenzo-p-dioxin	0.1
1,2,3,6,7,8-hexachlorodibenzo-p-dioxin	0.1

TABLE 2 TO SUBPART W OF PART 63—TOXIC EQUIVALENCY FACTORS—Continued

Dioxin and Furan Congener	Toxic equivalency factor
1,2,3,4,6,7,8-heptachlorodibenzo-p-dioxin	0.01
octachlorodibenzo-p-dioxin	0.0003
2,3,7,8-tetrachlorodibenzofuran	0.1
2,3,4,7,8-pentachlorodibenzofuran	0.3
1,2,3,7,8-pentachlorodibenzofuran	0.03
1,2,3,4,7,8-hexachlorodibenzofuran	0.1
1,2,3,6,7,8-hexachlorodibenzofuran	0.1
1,2,3,7,8,9-hexachlorodibenzofuran	0.1
2,3,4,6,7,8-hexachlorodibenzofuran	0.1
1,2,3,4,6,7,8-heptachlorodibenzofuran	0.01
1,2,3,4,7,8,9-heptachlorodibenzofuran	0.01
Octachlorodibenzofuran	0.0003

■ 164. Add Method 327 to appendix A of part 63 to read as follows:

Method 327—Fugitive and Area Source Measurement of Selected Volatile Organic Hazardous Air Pollutants Using Specially Prepared Canisters

1.0 Scope and Application

1.1 This method describes the sampling and analysis of emissions from fugitive and area sources collected using specially prepared canisters and analyzed using a gas chromatograph (GC) coupled with a low- or high-resolution mass spectrometer (MS) for the determination of the airborne concentration of selected volatile organic hazardous air pollutants (oHAPs) such as ethylene oxide or vinyl chloride.

1.2 Applicability. The use of this method is strictly intended for determining airborne concentrations of selected speciated oHAPs to determine compliance with a fenceline emission standard and/or work practices when specified by the applicable regulation. This method includes data quality objectives (DQOs) specific to the measurement of airborne concentrations of speciated oHAPs and must not be used for other compliance purposes (*i.e.,* measurements from ducted sources).

1.3 The analytical approach for this method uses a GC coupled with a low- or high-resolution MS, which may consist of a linear quadrupole, ion trap, or time-of-flight (TOF) system. Speciated oHAPs are identified by a combination of the retention times (RTs) and the associated mass spectra by comparing observed fragmentation patterns to reference spectral patterns and relative ion abundances established during calibration. For the speciated oHAPs, the intensity of the observed quantitation ion in the unknown sample is compared with the system response to the same ion for known amounts of the compound.

1.4 The sampling and analytical approach included in this method is based on previously published EPA guidance in Compendium Method TO–15A, which describes the sampling and analytical procedures for measuring volatile organic compounds (VOCs) in ambient air.

2.0 Summary of Method

2.1 In this method, a whole air sample is collected through a particulate filter with a flow control device into an evacuated, specially prepared canister for a length of time specified by the applicable regulation, typically 24 hours. After the air sample is collected, the canister valve is closed, the canister pressure is measured, and the canister is transported to the laboratory for analysis. Upon receipt at the laboratory, the sample collection information is verified, the canister pressure is measured, and the canister is stored at ambient laboratory temperature until analysis. For analysis, a known volume of the sample is directed from the canister into a preconcentrator to collect speciated oHAPs from the sample aliquot and to allow the majority of bulk gases (*e.g.,* nitrogen, oxygen, argon, and carbon dioxide) and water vapor to be vented.

2.2 The laboratory, field laboratory, and field personnel must have experience with sampling trace-level oHAPs using specially prepared canisters and with operating preconcentrator/GC/multidetector instrumentation (*e.g.,* MS) for trace-level analysis.

2.3 This method is performance-based and includes a description of the equipment, instruments, operations, and acceptance and performance criteria. EPA developed these criteria to ensure the collection of high-quality data. Laboratories must develop their own standard operating procedure (SOP) documents describing the equipment, equipment management, targeted compounds, procedures, and quality assurance (QA) activities specific to that laboratory, instrumentation, and potentially specific for the targeted analyte.

2.4 The key steps of this method required for the collection of each sample include stringent leak testing under stop flow, using certified and clean canisters, using certified sampling devices, collecting accurate field data, and collecting field blanks and duplicates. The key steps of this method required for sample analysis include the analysis of blanks, use of high-quality reference standards, and initial and ongoing calibration checks of the instruments used.

3.0 Definitions

3.1 *Absolute pressure* means the pressure measured with reference to absolute zero pressure, usually expressed in units of kilopascal (kPa) absolute or pounds per square inch absolute (psia).

3.2 *Analytical batch* means the batch of samples analyzed over a 24-hour period beginning with the daily instrument tune performance check.

3.2 *Collocated precision* means the precision determined from the analyzed concentrations of samples collected simultaneously from the same air mass using two discrete canisters and collected through two separate sampling devices with separate inlets. This determines the precision of the method including the sampling and analysis processes. Collocated precision is determined by calculating the absolute relative percent difference (RPD) for the collocated measurements (the absolute value of the difference between the two collocated sample results divided by their average value and expressed as a percentage).

3.3 *Continuing calibration verification sample (CCV)* means single level calibration samples run conducted periodically to confirm that the analytical system continues to generate sample results within acceptable agreement to the current calibration curve.

3.4 *Cryogen* means a refrigerant used to obtain sub-ambient temperatures in the preconcentrator and/or the GC oven. Typical cryogens are liquid nitrogen (boiling point [BP] −195.8 °C), liquid argon (BP −185.7 °C), and liquid carbon dioxide (BP −79.5 °C).

3.5 *Deionized water* means ASTM Type I water or equivalent.

3.6 *Diluent gas* means hydrocarbon-free (HCF) synthetic ''zero'' air.

3.7 *Dynamic dilution* means a technique for preparing calibration mixtures in which standard gas(es) from pressurized cylinders are continuously blended with a diluent gas (such as humidified HCF zero air) in a mixing chamber or manifold so that a flowing stream of calibration mixture is created.

3.8 *Gauge pressure* means the pressure measured with reference to the surrounding atmospheric pressure, usually expressed in units of kPa or inches of mercury (Hg). Gauge pressure is zero-referenced against ambient air pressure; zero is equal to the local atmospheric (barometric) pressure, which is nominally 101.3 kPa (29.92 in. Hg or 14.7 psia) at sea level.

3.9 *Mass spectrometer* means an instrument that ionizes molecules and atoms (typically into electrically charged fragments), separates these ions according to their mass-to-charge ratio (m/z or m/e), and responds to the impact of the ions based on their population. MS systems suitable for this method include quadrupole, ion trap, and TOF detectors. Quadrupole and ion trap MS operating modes (*i.e.,* full-scan, selected ion monitoring [SIM], and selected ion storage [SIS] modes) can be selected to optimize the ion mass collection range.

3.10 *Mechanical Flow Controlling Device (MFCD)* means a device that is used to ensure constant flow to an evacuated canister to near ambient pressure. MCFD are designed to maintain a constant pressure drop (and thus a constant flow rate) across a restrictive orifice by allowing a constant leak rate of sample into the canister as the canister vacuum decreases to near ambient pressure without power.

3.11 *Nominal concentration* means a requested, target, or named concentration that approximates the true, reference, or certified concentration. For example, a nominal 200 parts per trillion by volume (pptv) standard may have an actual certified concentration of 206 pptv.

3.12 *Preconcentrator* means a device used to concentrate the target compound(s) while the bulk gases are effectively removed. The target compound(s) are then desorbed and injected into a GC–MS system.

3.13 *Quantitative accuracy* means the degree of measurement accuracy required to measure the concentration of an identified compound, within a given tolerance of uncertainty, with an analytical system.

3.14 *Replicate precision* means the precision determined from repeated analysis of a gas sample from one canister, which may be evaluated by calculating the absolute RPD for pairwise measurements (N = 2) or by determining the relative standard deviation (RSD) for replicate measurements where $N \geq 3$. Replicate analyses are used to determine precision of the analysis processes and do not provide information on sampling precision.

3.15 *Second Source Calibration Verification (SSCV) Standard* means a humidified calibration standard prepared from a calibration stock gas procured from a separate supplier. An SSCV can only be prepared with a calibration stock from the same supplier if it is unavailable from another supplier and is prepared from a different lot of source material as the primary calibration stock.

3.16 *Static dilution* means a technique for preparing calibration mixtures in which standard and diluent gases are added to a fixed-volume vessel or chamber at a known ratio. Standard and diluent gas amounts may be measured gravimetrically, by volume, and/or by pressure differential from pressurized cylinders or as neat materials and blended with a known amount of diluent gas (such as humidified zero air) in a mixing chamber or manifold.

3.17 *Target concentration* means desired, estimated, or approximate concentration (see ''nominal concentration'' above).

3.18 *Theoretical concentration* means a reference concentration derived by applying measurements performed with calibrated instruments with known tolerances to a certified reference standard concentration value. Measurements of the target compound(s) concentrations are to be determined using a calibration that is developed based on theoretical concentrations.

3.19 *Time-of-flight (TOF) mass spectrometry* means a MS method that determines the ion's mass-to-charge ratio by measuring the time the ion takes to reach the detector.

3.20 *Wetted surfaces* mean the surfaces of the flow path, canister, valving, pumps, etc., that contact the gas undergoing collection, mixing, transfer, or analysis.

4.0 Interferences

4.1 Sample Collection. There are potential physical interferents which could impact the ability to properly time-integrate the sampling, such as leaks of the sampling system or introduction of foreign material (*e.g.,* particulate matter [PM], insect nests, spider webs). These interferences are mitigated by closely following the sampling protocols included in this method (*e.g.,* leak check procedures and sampling system requirements).

4.2 Canister Sampling Media Interferences. Each canister will have its own specific performance characteristics and appropriate cleaning, sampling, and handling procedures are required for attainment of acceptable initial and ongoing method performance. Failure to adhere to the cleaning and certification requirements included in this method may lead to the following interference issues:

(1) Incomplete deactivation of canister interior surfaces (*e.g.,* canister welds) may result in active sites for adsorption or surfaces that facilitate the decomposition of labile VOCs to form other VOCs within the canister. Other potential sources of active sites include canister valves, valve stems, and ferrules. Damage to the canister interior that exposes untreated surfaces may also result in active sites.

(2) Entrained PM deposited in the canister sampling pathway can adsorb VOCs making them unavailable in the canister gas phase which interferes with collected samples. Such trapped VOCs can potentially desorb later and result in the inability to achieve canister cleanliness performance specifications and/or contaminate subsequent canister sampling events. Additionally, organic PM can react with co-sampled ozone or other oxidative species to form target VOCs. PM can also clog tiny openings in critical or restrictive orifices, which impacts collection flow rates.

(3) Under certain conditions, the composition of an air sample may change upon its introduction into the canister and over time such that the air in the canister no longer represents the air sampled. Such changes may be caused by interactions of the VOCs with the interior canister surface or between chemicals in the air matrix. The activity of the interior canister surface is unique to each canister and is based on several factors, including variability in canister manufacturing defects, differences in

canister surface deactivation treatments, the presence of PM and co-collected moisture in the canister, and artifacts from reactions of VOCs on the canister walls.

(4) Condensed water within the canister can result in corrosion of the interior surface of canisters with weak or deficient coatings and can result in the partitioning of hydrophilic polar VOCs to liquid water. Under such circumstances, concentrations of these analytes in the gas phase will be biased low until the condensation is eliminated by reduction of the canister pressure below the vapor saturation pressure of water.

4.3 Analytical Interferences. Contamination within the analytical system may come from several sources including, but not limited to, off-gassing of materials within the sample introduction or preconcentrator flow path, carryover from high-concentration samples or standards, and solvent vapors within the laboratory.

(1) Active sites within the sample introduction or preconcentration flow path are often caused by use of improper materials or degradation of deactivated surfaces.

(2) Impurities in source materials or diluent gases for internal standard (IS) gas mixtures may result in contamination of target VOCs.

(3) Water and the delivery systems used to humidify canisters or diluent gas streams may contaminate the canister contents or humidified gases.

(4) Moisture in the sample gas may interfere with VOC analysis by GC–MS. Poor or inconsistent water management during preconcentration can cause peak broadening and RT shifts that can result in peak misidentification, particularly for hydrophilic polar compounds. Water management systems that use semipermeable fluoropolymer membranes remove oxygenated and polar VOCs from the sample matrix and exhibit memory effects for several VOCs. VOCs entrained in the fluoropolymer membrane can convert to ketones and alcohols, which are transported across the membrane bidirectionally such that these ketones and alcohols can contaminate the sample stream and VOCs in the sample stream can be adsorbed into the fluoropolymer and removed from the sample stream.

(5) Carbon dioxide in the collected sample can coelute with more volatile VOCs eluting early in the GC–MS run and interfere with their quantitation.

(6) Artifacts in chromatograms, such as silanol compounds formed from the breakdown of silicon-ceramic linings of canisters and siloxane compounds from the breakdown of the stationary phase in an analytical column, can interfere with identification and quantitation of less volatile VOCs.

(7) Be cognizant of compounds that interfere with target analytes when operating in MS modes that do not provide full-scan ion spectra (*i.e.,* selected ion monitoring [SIM] and selected ion storage [SIS]). Such interfering coeluting compounds may share common ions, may have similar mass spectra, and may be difficult or impossible to separate from target VOCs.

5.0 Safety

This method does not address all the safety concerns associated with its use. It is the responsibility of the user of this standard to establish appropriate field and laboratory safety and health practices prior to use.

6.0 Equipment and Supplies

6.1 Specially Prepared Canisters. You must use specially prepared canisters at least 6 liters in volume that are suitable for trace gas analysis of the target compounds, such that they meet the requirements in Section 8.3 of this method. Canisters must be able to withstand numerous cycles of evacuation to high vacuum of 0.0067 kPa (0.002 in. Hg) and pressurization to 377 kPa (40 pounds per square inch gauge, psig).

6.2 Valves. You must use canisters with valves that are designed specifically for trace level measurements. The wetted portions of the valve must, at a minimum, be constructed of chromatographic-grade stainless steel (preferably type 316), and the valve seal surfaces must be metal to metal to minimize absorption and off-gassing of VOCs and other potential contaminants. It is recommended that valve designs have minimal internal volume and surface area to minimize the risk of contamination.

6.3 Canister Cleaning System. You must use a canister cleaning system that includes the following components.

6.3.1 Manifold constructed of chromatographic-grade stainless-steel tubing and connections for multiple canisters.

6.3.2 Oil-free vacuum pump capable of achieving vacuum of approximately 3.4 kPa absolute (1 in. Hg absolute or 0.5 psia).

6.3.3 High-vacuum pump for achieving a final canister vacuum of approximately 0.0067 kPa (0.002 in. Hg) or less.

6.3.4 Heating oven that can contain the canister and allow heating of the valve. The oven is also used to bake sampling system components.

6.3.5 Humidification system, such as humidifier impinger or bubbler, capable of achieving relative humidity (RH) of at least 50% in the cannister.

6.3.6 Programmable controller for selecting temperature and cycle time and for manually or automatically switching between evacuation and pressurization.

6.3.7 A pressure release valve to minimize the likelihood of system over pressurization.

6.3.8 Tubing and connections constructed of borosilicate glass, quartz glass, or chromatographic-grade stainless-steel (minimum type 316 or silicon-ceramic coated) to minimize dead volume of the system. You must not use butyl rubber or perfluoroalkoxy (PFA) materials. If needed for connections or seals, minimize the use of Viton and Teflon to avoid adsorption and/or off-gassing of compounds of interest or introduction of other potential interferences.

6.3.9 Purge gas such as HCF zero air or ultra-high purity (UHP)-grade cylinder nitrogen or liquid nitrogen dewar headspace.

6.3.10 Charcoal scrubber, catalytic oxidizer, or other systems for eliminating trace contaminants from the purge gas.

6.4 Sampling Device. The sampling device consists of the following equipment and for the purpose of this method, the sampling device consists of the aggregation of equipment in this section. The sampling device must be individually named with an alpha-numeric serial number that is unique.

6.4.1 A stainless-steel particulate filter with pore size of 2 to 7 micrometers (µm) installed on the sampling device inlet.

6.4.2 Sampling Probe. The internal volume of the sample probe must be less than 1% of the volume collected by the sample container with an inverted inlet (*e.g.,* sampling cane to prevent the entry of water droplets) consisting of only chromatographic-grade stainless steel (including silicon-ceramic lined steel) placed 1.5 to 3 meters (4.9 to 9.8 feet) above the ground.

6.4.3 You must use an MFCD to regulate the flow at a constant flow rate over the 24-hour collection period into an evacuated stainless-steel canister.

6.4.4 Canister Sampling Timers (Optional). A device with an inert valve that can be programmed to automatically start and stop canister sampling periods

6.5 Vacuum/Pressure Gauges.

6.5.1 Field Pressure Measurement Gauge. A vacuum/pressure gauge or pressure transducer with an accuracy of ±0.25% full scale calibrated over the range of use for the application with sufficient resolution to permit precise measurement of pressure differentials must be used for field sampling purposes. The accuracy of the vacuum gauge must be measured verified on an annual basis against a National Institute of Standards and Technology (NIST)-certified standard.

6.5.2 Laboratory Canister Pressure Measurement Gauge. A vacuum/pressure gauge or pressure transducer with an accuracy of ±0.1% full scale or 0.13 kPa, whichever is smaller, calibrated over the range of use for the application with sufficient resolution to permit precise measurement of canister pressure must be used for pressurizing field samples with HCF zero air or ultrapure nitrogen for analysis. The accuracy of the vacuum gauge must be measured verified on an annual basis against a NIST-certified standard for analysis.

6.6 Gas Regulators. Regulators for high-pressure cylinders of dilution gas, stock standard gases, and internal standard gases must be constructed of non-reactive material, such as high-purity stainless steel, and may be lined with an appropriate material that is inert to the targeted VOC (*e.g.,* silicon-ceramic). Do not use regulators that contain PFA materials (*e.g.,* for seals and diaphragms) and avoid using regulators that contain Teflon products such as polytetr-rafluoroethylene (PTFE) and flouroethylenepropylene(FEP), where possible, to minimize memory effects. All regulators must be rated for the pressure and flow expected during use. Regulators must be dedicated to a specific task and labeled for use (*e.g.,* do not use the same regulator on a high-concentration stock VOC standard cylinder and a low-concentration stock VOC cylinder).

Note: Some new regulators (*e.g.,* stainless steel regulators) should be sufficiently passivated prior to use to prevent potential sample loss.

6.7 Reference Flow Meters.

6.7.1 A flow meter (*e.g.,* a calibrated mass flow meter (MFM), a volumetric reference standard, or other similar measurement device) calibrated to measurement range appropriate to measure continuous flow must be used. The flow meter must not interfere with the flow measurement (*i.e.,* the pressure drop across the flow meter may affect the flow being measured).

6.7.2 Reference flow meters must be calibrated on an annual basis and be able to measure within ±2% of the predicted values (*e.g.,* cubic centimeters per minute) against a NIST-traceable volumetric standard.

6.8 Tubing and Fittings. Connecting tubing and fittings for dilution and standard gases must be constructed of chromatographic-grade stainless steel (*e.g.,* 316 type), which includes silicon-ceramic–treated stainless steel. Connections must be metal to metal. Lines may need to be heated to ensure that there is no condensation. You must not use PTFE thread sealants or Buna-N rubber components on any wetted surface in a sampling and analytical system.

6.9 Analytical Instrumentation. Conduct analyses under this method using any combination of preconcentrator, GC, and MS provided the equipment meets the performance specifications of this method.

6.9.1 Gas Chromatographic–Mass Spectrometric (GC–MS) System.

6.9.1.1 Gas Chromatograph. The GC used for analysis under this method must allow temperature programming with quick and accurate temperature ramping. If needed for separation of very light VOCs from the targeted oHAPs, the GC must be capable of sub-ambient cooling (*e.g.,* −50 °C). Carrier gas connections must be constructed of stainless-steel or copper tubing.

6.9.1.2 Chromatographic Column. The capillary chromatographic column must be capable of achieving separation of target compounds and any potential interferences per Section 4 and maintaining retention time stability as required in Section 9.

6.9.1.3 Mass Spectrometer. The MS may be a linear quadrupole, ion trap, or TOF unit, and must have minimum resolution of 1 atomic mass unit (amu) or less. The MS must be capable of analyzing the desired mass range every 1 second or less and operate with an acquisition rate such that at least 12 measurements are performed over a typical chromatographic peak. Quadrupole and ion trap systems employing electron impact (EI) ionization mode must provide nominal 70 volt (V) electron energy in EI mode to produce a bromofluorobenzene (BFB) mass spectrum that meets all the instrument performance acceptance criteria as specified in this method.

6.10 Calibration Gas Standard Preparation Equipment. This section discusses the equipment needed to prepare working-level standards for calibrating the GC–MS by dilution of a higher concentration stock standard gas.

6.10.1 Dynamic Dilution System Instrumentation.

6.10.1.1 The dynamic dilution system must include, at a minimum, calibrated electronic mass flow controllers (MFCs) for the diluent gas and each standard gas to be diluted, a humidifier for the diluent gas, and a manifold or mixing chamber where the diluent and standard gases can be sufficiently combined before introduction to the preconcentrator or canister. The gas dilution system must produce calibration gases whose measured values are within ±2% of the predicted values. The predicted values are calculated based on the certified concentration of the supply gas (protocol gases, when available, are recommended for their accuracy) and the gas flow rates (or dilution ratios) through the gas dilution system.

6.10.1.2 Connection tubing for the dynamic dilution system must be constructed of chromatographic-grade or silicon-ceramic–coated stainless steel. Mixing chambers or manifolds must be constructed of chromatographic-grade or silicon-ceramic–coated stainless steel, borosilicate, or quartz glass.

6.10.1.3 The gas dilution system must be recalibrated at least once per two calendar years using NIST-traceable primary flow standards with an uncertainty ≤0.25%. You must report the results of the calibration whenever the dilution system is used, listing the date of the most recent calibration, the due date for the next calibration, calibration point, reference flow device (device identification [ID], serial number [SN], and acceptance criteria.

6.10.1.4 The gas dilution system must be verified to be non-biasing under HFC zero air and known standards at least one per calendar year for each reactive target compounds (*e.g.,* ethylene oxide and vinyl chloride). Zero air must be flowed through all applicable MFCs, tubing, and manifold used and verified to not be detectable for the target compounds. Additionally, a known standard within the calibration range of the analytical system for each target compound must be flowed through all applicable MFCs, tubing, and manifold to allow equilibration and verified to not bias the standard by ±15% of the concentrations in the reference sample. The equilibration time for the bias verification must be used at a minimum for the development of standards.

6.10.1.5 The gas dilution system MFCs used must be verified quarterly, at a minimum, per Section 3.2 of Method 205 using any available protocol gas and corresponding reference method.

6.10.2 Static Dilution System Instrumentation.

6.10.2.1 The static dilution system must include, at a minimum, a calibrated pressure transducer or pressure gauge to measure the partial pressures of each standard gas to be diluted and the balance gas, and a manifold to introduce the gases into the working standard canister or vessel. Pressure transducer(s) or pressure gauge(s) used for static dilution must have an accuracy of ±0.1% full scale or 0.13 kPa, whichever is smaller, calibrated over the range of use for the application with sufficient resolution to permit precise measurement of pressure differentials.

6.10.2.2 Connection tubing for the static dilution system must be constructed of chromatographic-grade or silicon-ceramic–coated stainless steel. Manifolds must be constructed of chromatographic-grade or silicon-ceramic–coated stainless steel, borosilicate, or quartz glass.

6.10.2.3 The static gas dilution system must be recalibrated once per calendar year using NIST-traceable primary pressure gauge with an uncertainty ≤0.1%. You must report the results of the calibration whenever the dilution system is used, listing the date of the most recent calibration, the due date for the next calibration, calibration point, reference flow device (ID, S:N ratio), and acceptance criteria.

6.10.2.4 The gas dilution system must be verified to be non-biasing under HFC zero air and known standards at least one per calendar year for each reactive target compounds (*e.g.,* ethylene oxide and vinyl chloride). Zero air must be flowed through all applicable tubing and manifold used and verified to not be detectable for the target compounds. Additionally, a known standard within the calibration range of the analytical system for each target compound must be flowed through all applicable tubing and manifold into the standard canister or vessel and verified to not bias the standard by ±15% of the concentrations in the reference sample.

6.11 Calibrated Hygrometer.

6.11.1 The calibrated hygrometer must be capable of a 1% RH resolution with a yearly calibration to a NIST-traceable accuracy of ±3% RH within the range of 20% to 80% RH.

6.11.2 The calibration hydrometer calibration must be verified weekly or per use (whichever is less stringent) at a single point that is approximatively 40 to 50% RH to within ±5% using a second calibrated hygrometer or a saturated salt solution.

7.0 Reagent and Standards

7.1 You must use only NIST-certified or NIST-traceable calibration standards, standard reference materials, and reagents that are stable through certification and recertification for the tests and procedures required by this method. You must use standards and reagents within their expiration period and evaluate working-level standards prepared in canisters within 30 days of preparation. The concentrations of the target compounds in the mixture must be commensurate with the anticipated dilution factor achievable by the laboratory needed to dilute the mixture to the desired working range. You must retain and report the gas standard certificates of analysis.

7.2 Carrier Gas. Use helium, hydrogen, or nitrogen as the carrier gas in the GC. Carrier gas must be ultrapure (99.999% pure or better).

7.3 HCF Zero Air. Purchase HCF zero air in high-pressure cylinders from reputable gas vendors or prepare HCF zero air by passing ambient air through molecular sieves, catalytic oxidizers, and subsequent charcoal filters or similar substrate. HFC zero air must contain impurities less than 20 pptv or undetected (whichever is more stringent) per compound of interest.

7.5 Nitrogen. Use ultrapure (99.999% pure or better) nitrogen from cylinders procured from commercial gas vendors or from the headspace gas from a liquid nitrogen dewar.

7.6 Cryogens. Cryogens (*e.g.,* liquid nitrogen, liquid argon, and liquid carbon dioxide) specified by the instrument manufacturer, if needed.

7.7 Water for Canister Humidification. ASTM Type I (resistivity ≥18 megaohm-centimeter [MΩ·cm]) or equivalent.

8.0 Sample Collection and Preparation

This section presents the sample collection and handling procedures of this method with the initial and ongoing performance evaluation of materials used in sampling and analysis. This method allows the user to choose the materials used for sampling. You must record the exact materials used when conducting this method and include that information in any report associated with sampling according to this method.

8.1 Sampling Device Performance Tests. Prior to initial field deployment and as directed in this section, you must verify that all equipment used to conduct this method meets the performance criteria specified in this section. The primary objectives of the performance tests in this section are to characterize the sampling system and to verify that the sampling system used meets the criteria in the method. The sampling system performance tests include the following:

(a) Flow control verification test,
(b) Flow control flow check,
(c) Sampling device leak check,
(d) Sampling device bias check, and
(e) Sampling device standard check.

8.1.1 Flow Control Verification Test. Prior to initial field deployment and at least every twelve months, you must verify that the sampling device's ability to control flow to the canister is acceptable. Assemble an evacuated canister with the sampling device including filter connected to a certified flow meter. Figure 1 of Section 17 of this method provides an illustration of the apparatus for characterizing the flow control device.

8.1.1.1 Open the evacuated canister, monitor and record (manually or electronically) the canister pressure downstream of the flow control device and the flow upstream of the flow control device on an hourly basis over the period of 24-hours.

8.1.1.2 The flow control verification test is considered acceptable when the sampling apparatus maintains a constant flow rate for 24-hours and until at least 75% of the canister volume is collected, which is equivalent to approximately 28 kPa (7 in. Hg or 4 psia) below atmospheric pressure.

8.1.1.3 Record the average flow rate during this test. This value will be the reference flow rate for the sampling device until the next verification test. Maintain the results as part of a laboratory record associated with the sampling device.

8.1.2 Flow Control Flow Check. Prior to and after each field sampling event, establish or verify the flow rate of the sampling apparatus. This verification must occur in the field prior to and after each field event.

8.1.2.1 Assemble an evacuated canister and the sampling device connected to a certified flow meter in the same manner used for the flow control verification test discussed above.

8.1.2.2 Open the evacuated canister, allow sufficient time for the system to stabilize, and record the flowrate upstream of the flow control device. Collect two additional flow rate measurements.

8.1.2.3 Calculate the average flowrate. The flow control flow check is considered valid if within ±10% of the reference flow rate.

8.1.2.4 If the flow rate has changed and is outside the desired range, you must either adjust or replace the controller and repeat the flow check.

8.1.3 Sampling Device Leak Check. You must demonstrate the sampling device and sampling system are leak-free immediately before you begin sampling.

8.1.3.1 Install the sampling device on an evacuated canister equipped with a MFCD and tightly cap the inlet to the sampling device.

8.1.3.2 Open the canister valve fully, and then re-close the valve and observe the vacuum/pressure gauge for a minimum of 2 minutes.

8.1.3.3 If you observe an increase in pressure, the sampling device does not qualify as leak-free. If no changes are observed, record the data and time of the leak check on the Field Data Page (see Figure 4 in Section 17 of this method for an example).

8.1.4 Sampling Device Bias Check. You must demonstrate that sampling device is non-biasing under zero-air and known-standard conditions. For the procedures in Sections 8.1.5 and 8.1.6 of this method, you must use only canisters that have been qualified as specified in Section 8.3 of this method.

8.1.5 Sampling Device Zero-Air Challenge. You must conduct the sampler bias test at least every twelve months, and after cleaning, replacement of components, or collection of potentially contaminating samples. The volume of air analyzed for the zero-air and reference standard gas must be consistent with the laboratory's typical canister sample injection volume or nominal volume.

8.1.5.1 Provide humidified (>40% RH) HCF zero air through the sampling device into the canister, and then analyze the sample according to Section 11 of this method and record the concentration measurement and maintain the results as part of a laboratory record associated with the sampling device.

8.1.5.2 The results must show that the concentration of the target compounds in the zero-air challenge sample collected through the sampling unit is not greater than 20 pptv higher than the native concentration of the target compounds in the reference sample (sample of zero-air collected upstream of the sampling device) or not detected at 22.1 psi absolute (152 kPa absolute) whichever is more stringent. If a sampling device does not meet this performance criteria, take action to remove the contamination attributable to the sampling unit (*e.g.,* purging with humidified HCF zero air overnight or longer) and repeat the zero-air challenge. You must not use a sampling device that has not met the standards in this section.

Note: If extended purging durations are not adequate to eliminate contaminants, then disassemble and clean according to Section 8.4 of this method. If the unit cannot be cleaned to meet the specifications, retire the unit from use or repurpose for source sampling.

8.1.6 Sampling Device Standard Check. You must conduct the sampling device standard check prior to initial use and at least every twelve months, and after replacement of components, or collection of potentially contaminating samples. For the procedures specified below, you must use only canisters that have been qualified as specified in Section 8.3 of this method.

8.1.6.1 Collect a humidified (>40% RH) known-standard challenge gas through the sampling device and into a canister. The challenge gas must contain the target oHAPs at 100 to 500 pptv each and you must choose the selected challenge concentration considering the expected measured concentration at the deployment location(s).

8.1.6.2 Analyze the sample according to Section 11 of this method and record the concentration measurement and maintain the results as part of a laboratory record associated with the sampling device. The results must demonstrate that each oHAP in the sample collected through the sampling device must be within ±15% of the concentrations in the reference sample. For compounds exceeding this criterion, you must take steps to eliminate the bias (*e.g.,* cleaning as specified in Section 8.6.1 of this method or replacement of compromised parts) and repeat the known-standard challenge.

8.1.6.3 Following successful completion of the known-standard challenge, flush the sampling device or system with humidified (>50% RH) HCF zero-air or ultrapure nitrogen until the device meets the criteria specified in Section 8.1.5.2 prior field deployment.

8.2 Qualification of Analytical Instrumentation. Prior to initial use and as directed in this section, you must verify that the analytical equipment used in performing this method meets the performance criteria in this section. The primary objectives of these performance tests are to characterize the analytical instrumentation and verify that the analytical instrumentation meets the criteria in this method. The analytical instrumentation performance tests consist of the following:

(a) Analytical zero-air verification,

(b) Analytical known-standard challenge for analytical instrumentation, and

(c) Autosampler verification.

8.2.1 Analytical Zero-Air Verification. Prior to initial use and as part of an instrument's annual calibration, you must demonstrate that the analytical instrumentation (preconcentrator, GC–MS system, and all connections) is non-biasing under zero-air. The volume of air analyzed must be consistent with the laboratory's nominal injection volume.

8.2.1.1 Use the analytical instrumentation to analyze humidified (40 to 50% RH) HCF zero air from a known clean source (*e.g.,* certified clean canister, clean cylinder gas, zero-air generator) at the installation prior to initial use of the instrument.

8.2.1.2 Examine chromatograms for interferences and other chromatographic artifacts such as nontarget peak responses, large peaks or rises in the chromatogram due to undifferentiated compounds, and baseline anomalies. The analysis must show that the concentration of any detected target compounds in the zero-air challenge sample is <20 pptv or undetected (whichever is more stringent) per compound of interest.

8.2.1.3 If you identify exceedances of target compounds in the zero-air challenge, take steps (*e.g.,* analyzing replicates of humidified clean gas until the contamination is eliminated) to remove the contamination attributable to the analytical instrumentation by following the manufacturer's instructions.

8.2.1.4 You must repeat the analytical zero-air verification to ensure that you have mitigated any problems before using the analytical instrumentation.

8.2.2 Analytical Known-Standard Challenge for Analytical Instrumentation. Prior to initial use and as part of an instrument's annual calibration, you must demonstrate that the analytical instrumentation (preconcentrator, GC–MS system, and all connections) is non-biasing under known standards. The volume of air analyzed must be consistent with the laboratory's nominal canister sample injection volume.

8.2.2.1 Analyze a humidified (40 to 50% RH) reference standard in duplicate containing all target compounds at approximately 100 to 500 pptv each, chosen in consideration of the expected concentration at the deployment locations.

8.2.2.2 The results must demonstrate that the target compounds in the sample collected through the sampling device are within ±15% of the expected concentrations in the sample.

8.2.2.3 Compounds demonstrating poor response as indicated by peak absence or minimal peak area may be a result of active sites in the analytical system, cold spots in transfer lines, gas impurities, improper choice of preconcentrator sorbent traps or GC columns, system leaks, and/or poor moisture management. If you identify problems, consult the instrument manufacturer to determine the necessary steps to eliminate the bias.

8.2.3 Autosampler Verification. Prior to initial use and as part of an instrument's annual calibration, you must demonstrate that the auto sampling equipment is non-biasing under zero-air.

8.2.3.1 If you use an autosampler to facilitate analysis of multiple canisters, you must test all ports, transfer lines, and connections of the autosampler after you have calibrated the analytical system and prior to conducting the canister, sampling device and system qualifications, or upon replacement of transfer lines or after analysis of potentially contaminating samples.

8.2.3.2 Connect humidified (40 to 50% RH) HCF zero air to each port and verify that the concentration for each target compound is <20 pptv or undetected (whichever is more stringent) per compound of interest using the procedures in Section 11 of this method.

8.2.3.3 After the zero-air test, challenge each port of the autosampler with a reference standard (approximately 100 to 500 pptv) to verify that the autosampler is not causing bias using the procedures in Section 11 of this method). The concentration of each target compound must be within ±15% of the theoretical concentration of the reference standard.

8.3 Qualification of Canisters. Prior to initial use and as directed in this section, sampling canisters must meet the performance criteria in this section. The primary objectives of these performance tests are to ensure canisters are well characterized and to verify they are non-biasing. The performance criteria in this section are specific to the application of fenceline measurements for regulatory purposes at stationary sources. The performance test consists of the following:

(a) Canister design,
(b) Canister leak check,
(c) Canister zero-air verification, and
(d) Canister known-standard verification.

8.3.1 Canister Design.

8.3.1.1 You must use specially prepared canisters at least 6-liters volume in size that are suitable for trace gas analysis of the target compounds. The canister must include a fixed on/off valve made from chromatographic-grade stainless with metal valve seal surfaces. Each canister must also include a permanent alpha-numeric serial number for identification purposes. Alternative canister volumes may be used, subject to approval by the Administrator.

Note: Specially prepared canisters are commercially available with a modest range of options for surface preparation of the canister interior surfaces, valves, and connections. Currently, canister interior surfaces are typically passivated by electropolishing or coating with a silicon-ceramic film. EPA does not require a specific treatment or design and any canister type may be used for this method contingent on meeting the performance criteria in this section; however, silicon-ceramic coated canisters have demonstrated superior performance when used to sample reactive compounds, (*e.g.,* ethylene oxide).

8.3.1.2 Canisters should be handled with care to ensure that the interior canister surface is not compromised, the valve-to-canister connection remains intact, and weld integrity is maintained. Excessive torque on unbraced canister valve stems when making connections may cause damage and potentially leaks in the valve stem weld or at the ferrule sealing the canister valve and canister stem. Shocks resulting in dents to the surface of the canister may damage welds or create small cracks in the interior canister surface that may expose active sites. You must not use any canister with dents or compromised welds.

8.3.1.3 You must maintain a record of the results for all canisters used for this method. It is recommended that you evaluate the results for any potential trends that could result in erroneous data.

8.3.2 Canister Leak Check. You must qualify each canister as being acceptably leak-tight to ensure sample validity. Qualify new canisters before initial use and qualify all canisters used for sampling at least annually.

8.3.2.1 Leak Check. In conducting the canister leak check, you can either evacuate the canister to high vacuum ≤0.0067 kPa absolute (0.002 in. Hg or 0.001 psia) or pressurize the canister with clean fill gas to >203 kPa absolute (60 in. Hg or 29.4 psia).

8.3.2.2 After establishing the target pressure in the canister, close the valve and attach a vacuum/pressure gauge.

8.3.2.3 Open the valve and record the initial pressure reading.

8.3.2.4 Close the valve, remove the vacuum/pressure gauge, and loosely cap the canister using a cap fitting to ensure that leakage through the valve is accurately assessed while avoiding potential entry of debris into the valve during storage.

8.3.2.5 After a minimum of two days in storage, reinstall the vacuum/pressure gauge, open the valve, and record the canister pressure reading.

8.3.2.6 Determine the pressure decay rate as the absolute value of the difference between the initial and post-storage canister pressures. You must remove the canister from service if the pressure decay rate exceeds 0.69 kPa/storage day (0.2 in. Hg or 0.1 psia/storage day).

8.3.3 Canister Zero-Air Verification. You must qualify each canister as being acceptably non-biasing under zero-air conditions to ensure sample validity. Qualify new canisters before initial use and qualify all canisters used for sampling at least once every 18 months.

8.3.3.1 Pressurize the clean evacuated canister with humidified (>50% RH) HCF zero air to 152 kPa absolute (22.1 psia). Do not use ultrapure nitrogen to pressurize the canister because the inert nitrogen atmosphere does not permit reactions within the canister that may occur under sampling conditions.

Note: Canister Zero-Air Verifications must also be performed after canister disassembly and/or replacement of components. Also, more frequent zero-air verifications may be appropriate when canisters are used in areas with higher ambient VOC concentrations or for collection of potentially contaminating samples.

8.3.3.2 Allow the canister to equilibrate for a minimum of 24 hours.

8.3.3.3 After the equilibration period, conduct an initial cleanliness analysis as specified in Section 8.4 of this method.

8.3.3.4 Store the canister for a holding period equal to or exceeding the typical laboratory holding time, nominally 8 days from the canister fill date.

8.3.3.5 After the holding period, conduct a subsequent cleanliness analysis as specified in Section 8.5 of this method.

8.3.3.6 The results of both the initial and subsequent cleanliness analysis must meet the cleanliness criteria specified in Section 8.5 of this method to be used for sampling. You must reclean and retest canisters that fail the zero-air challenge.

Note: If necessary, use more aggressive cleaning techniques such as water rinses or other rinses as specified by manufacturers. If a canister continues to fail the zero-air challenges, remove the canister from service.

8.3.4 Canister Known-Standard Verification. You must qualify each canister as being acceptably non-biasing under known-standard conditions to ensure sample validity. Qualify new canisters before initial use and qualify all canisters used for sampling at least every 18 months.

8.3.4.1 Fill the clean evacuated canister with a humidified (40 to 50% RH) standard gas in HCF zero air with each target compound at approximately 100 to 500 pptv. Choose the selected challenge concentration based on the concentration expected to be measured during the sampling event.

8.3.4.2 Allow the canister to equilibrate for a minimum of 24 hours.

8.3.4.3 After the equilibration period, conduct an initial analysis according to Section 11 of this method.

8.3.4.4 Store the canister for a holding period equal to or exceeding the typical laboratory holding time, nominally 8 days from the canister fill date.

8.3.4.5 After the holding period, conduct a subsequent analysis.

8.3.4.6 The results of both the initial and subsequent analysis must show that the measured concentrations of the target analytes are within ±30% of the theoretical spiked concentration for each target compound. You must reclean and retest canisters that fail the known-standard verification.

8.4 Canister Cleaning. Clean canisters using repeated cycles of evacuation and pressurization. Table 1 in Section 17 of this method summarizes the canister cleaning procedures.

8.4.1 Gas Source for Canister Cleaning, Pressurization, and Flushing.

8.4.1.1 Verify, by direct analysis, the cleanliness of the purge gas upon initial setup. The analysis must show that the concentration of the individual target compounds is ≤20 pptv or undetected (whichever is more stringent) per compound of interest at 101.3 kPa absolute (29.92 in. Hg or 14.7 psia).

8.4.1.2 Humidify the purge gas to >50% RH and measure the humidity by placing a calibrated hygrometer probe in the humidified gas stream.

8.4.1.3 If using a bubbler-type humidifier, ensure that the downstream pressure is lower than the humidifier upstream pressure to avoid backflow of the water.

8.4.2 Pre-Evacuation of Canisters. You may need to repeat the pre-evacuation process for canisters that contain VOCs at higher concentrations.

8.4.2.1 Pre-evacuate canisters to be cleaned prior to connection to the canister cleaning system. To reduce the potential for contamination of the system, attach the canisters to an oil-free roughing pump and evacuate to approximately 7 kPa absolute (28 in. Hg vacuum or 1.0 psia) with the exhaust of the pump directed to a fume hood or passed through a charcoal trap.

8.4.2.2 Refill canisters to ambient pressure with HCF zero air.

8.4.2.3 Attach the canisters to the cleaning system after completing the pre-evacuation and refilling steps.

8.4.3 Canister Heating During Cleaning.

8.4.3.1 Heat canisters by placing them in an enclosed oven during cleaning to facilitate removal of compounds. Do not use heat bands or heating jackets.

8.4.3.2 Table 1 of Section 17 of this method specifies the temperatures to use for canister cleaning procedures.

8.4.4 Canister Evacuation and Pressurization Cycling.

8.4.4.1 Evacuate canisters to minimally 7 kPa absolute (28 in. Hg vacuum or 1 psia) and maintain this vacuum for a at least 1 minute.

8.4.4.2 Pressurize canisters to 414kPa absolute (≤30 psig) with humidified (>50% RH) HCF zero air and maintain this pressure for a minimum of 1 minute.

8.4.4.3 Repeat the cycle of canister evacuation and pressurization specified in Sections 8.4.4.1 and 8.4.4.2 of this method at least 5 times. You may need to perform 10 to 20 cycle repetitions or use other ancillary procedures to remove stubborn interferents or oxygenated compounds such as ketones, alcohols, and aldehydes (U.S. EPA, 2016b).

8.5 Verification of Canister Cleanliness Prior to Sample Collection.

8.5.1 After cleaning, pressurize each canister from the batch with humidified HCF zero air and maintain that pressure for at least 24 hours.

8.5.2 Connect each canister to the analytical system and measure the concentration of each target compound according to the procedures in Section 11 of this method.

8.5.3 The canister background concentration for each target compound must be ≤20 pptv (0.02 ppbv) or undetected (whichever is more stringent) when a canister is filled to 22.1 psi absolute (152 kPa absolute).

8.5.4 Canisters that meet the blank criteria are suitable to be evacuated for use. If a canister fails to meet the criteria, you must not use that canister until it has been re-cleaned and has met the requirements in Section 8.5.3 of this method.

8.5.5 Prior to field deployment, evacuate canisters to ≤0.0067 kPa (≤0.002 in. Hg or 0.001 psia).

8.6 Cleaning of Sampling Components.

8.6.1 Follow the manufacturer's instructions for cleaning components such as flow controllers and sampling unit parts, when necessary.

Note: *Disassembly of such instruments may void warranties or calibrations.*

8.6.1.1 Flush the sampling units with humidified HCF zero air to remove contamination for at least 15 minutes.

8.6.1.2 Disassemble sampling components and visually inspect for cracks, abrasions, and residue prior to sonicating in deionized water for at least 30 minutes.

8.6.1.3 After flushing/sonication, rinse the components with clean deionized water and dry the components in an enclosed oven set to at least 50 °C for a minimum of 12 hours.

8.6.1.4 Following drying, reinspect components for defects, reassemble, and flush the sampler with humidified HCF zero air or ultrapure nitrogen for at least 12 hours.

Note: *To avoid damage to deactivated stainless-steel components due to oxidation in the presence of oxygen-containing atmospheres (e.g., HCF zero air), you should not heat components treated with silicon-ceramic coatings above 80 °C unless evacuated or under an inert atmosphere (e.g., nitrogen).*

8.7 Sample Collection. Persons collecting field samples should be familiar with all aspects of this sampling protocol. It is suggested that those collecting these measurements for regulatory purposes develop site-specific SOPs to ensure samples are collected consistently and those doing the sampling are sufficiently trained on this method and the SOP.

8.7.1 Pre-Sampling Activities.

8.7.1.1 Clean canisters and verify that the canisters meet cleanliness and vacuum criteria specified in Sections 8.3 through 8.5 of this method.

8.7.1.2 If canisters were previously cleaned and stored under pressure while awaiting use, you must evacuate the canisters prior to field deployment. If canisters were stored under vacuum, you must verify that the canisters continue to meet vacuum threshold requirements.

8.7.1.3 Clean and verify the cleanliness and flowrates of sample devices that you will use for sampling and ensure that a clean particulate filter is placed in the inlet of the sampling device.

8.7.1.4 Establish sample codes (unique identifiers) and develop field data page and/or chain of custody (COC)/sample collection data form(s).

8.7.1.5 If shipping equipment into the field, make sure you have the proper number of canisters and sampling devices for the number of samples required for the sampling location and QC samples, allowing for sufficient timing for samples to arrive at the site.

8.7.1.6 Develop a unique sampling location ID. The sampling location must meet any requirements set in the applicable regulation and be in a secure location that protects the canister and sampling inlet from unwanted tampering or damage. The sampling location must also be located away from the immediate vicinity of any biasing sources (*e.g.,* outdoor smoking areas; vehicle exhaust; heating, ventilation, and air conditioning units/building exhaust; outdoor fuel storage areas; shelter roofing materials; or exhaust from other sample collection devices). In general, horizontal distances should be >10 meters (m) from biasing sources.

8.7.2 Sample Setup Activities.

8.7.2.1 You must place the canister in a location that protects the canister and sampling inlet from unwanted tampering, damage, or theft.

8.7.2.2 Protect the canister and sampling inlets by placing the canister under shelter, if possible. Do not restrict air flow around inlets and do not locate inlets under building overhangs.

8.7.2.3 Do not place the canister near vegetation or structures that block or significantly restrict air flow to the MFCD inlet or manifold. Ensure that rain cannot be drawn directly into the MFCD, and the inlet heights must be approximately 1.5 to 3 m above ground level.

8.7.3 Sample Setup and Deployment. Perform the following steps at the time of sample setup and deployment.

8.7.3.1 Based on the applicable standard, determine the appropriate number and placement of sampling locations at the fenceline. The applicable standard will define the sampling schedule (*e.g.,* one sampling event over a 5-day period) and the sampling period. All sampling locations must initiate sampling within 60 minutes of each other.

8.7.3.2 You must document all activities associated with sampling on the field data page. (See Figure 4 in Section 17 of this method for an example field data page.) You may choose to use this field data page as the COC, or you may choose to establish a separate COC form. The chain of custody will accompany the canisters during shipment and collection to document sample handling and transport.

8.7.3.4 Verify that each canister has been blanked within the last 30 days. Label each canister with a sample ID code and record the canister and sample ID on the field data page. You must not use a use a canister for sampling that has not been blanked within 30 days of sampling.

8.7.3.5 Verify the sample device is in working order and calibrate/verify the flow rate setting, if applicable, with a reference flow meter. Record the sample device ID, expected flowrate, and the reference flowrate if calibrated/verified in the field, including the reference flow meter if applicable.

8.7.3.6 Attach the sampling device to the canister and locate at the appropriate sampling location. Record the sampling location ID, latitude, longitude, date, and time that you installed the canister on the field data page.

8.7.3.7 Measure and record the canister vacuum using the field pressure measurement gauge, and verify that the canister has not leaked and has sufficient vacuum to collect the sample. You must replace the canister if the initial pressure is not within −1 in. Hg absolute zero (−3.39 kPa or 0.5 psi).

8.7.3.8 Conduct leak checks as specified in Section 8.3.2 of this method and record the results on the field data page.

8.7.3.9 Open the canister valve. Record the date and time that you opened the valve as the start time, and record the initial canister vacuum/pressure and any other comments such as unusual events or conditions that may impact sample results on the field data page.

8.7.3.10 Sample for the period as defined in the applicable standard (*e.g.,* 24 hours +/−1 hour).

8.7.3.11 At the end of the sampling period, close the valve. Record the date and time that you closed the valve as the end time.

8.7.3.12 Remove the sampling device and attach the field pressure measurement gauge.

8.7.3.13 Open the canister valve and measure and record the final canister vacuum/pressure and any other comments such as unusual events or conditions that may impact sample results on the field data page. Flag any canisters with a final pressure greater than −3 in. Hg gauge pressure (10.2 kPag or −1.5 psig).

8.7.3.14 Disconnect the field canister pressure measurement gauge and replace with a cap.

8.7.3.15 If applicable, verify the sample device is still in working order and verify the flow rate setting with a reference flow meter. Record the final flowrate on the field data page.

8.7.4 Field Duplicates. For each sampling day, you must include the collection of a separate co-located sample for at least one sampling location. The collocated duplicate must be sampled using a discrete MFCD. The collection of the field duplicates must follow the same procedure and occur at the same time as the co-located field sample.

8.7.5 Canister Field Blanks. For each sample day, you must collect canister field blanks. A canister blank is prepared by filling a canister with humidified clean diluent gas (prepared in the same manner as the method blank (MB) described in Section 9.3.2 of this method) to approximately 15 in. Hg ± 1 in. Hg . Record the pressure and transport to the field site(s) to accompany field-collected canisters. Canister field blanks are to be treated identically to field-collected samples in the field and laboratory including pressure checks, MFCD leak checks, etc. The field blanks are analyzed by interspersing them among the field samples.

8.7.6 Canister Field Spike. For each sample day, you must collect a canister field spike. A canister field spike is prepared by filling a canister with humidified standard gas at a concentration in the lower third of the calibration curve for the target compound to approximately −15 in. Hg ± 1 in. Hg. The field spike canister is transported to the field site to accompany field-collected canisters and treated identically to field-collected samples in the field and laboratory, including pressure checks, MFCD leak checks, etc. The field spikes are analyzed by interspersing them among the field samples. Field spike acceptance criteria should be within ±30% of the theoretical spiked concentrations.

8.7.7 Prepare and secure the canisters for transport. You must ship canisters in protective hard-shell boxes and/or sturdy cardboard boxes to ensure canister longevity. Do not use boxes that have lost integrity or rigidity.

8.8 Method Detection Limit (MDL) Determination. Determine the MDL under the analytical conditions selected (see Section 11 of this method) using the procedures in this section.

8.8.1 Prepare at least seven blank samples according to the procedures Section 9.3.2 of this method using sampling media (*i.e.,* canisters) that have been deployed in the field, and cleaned per Section 8.4 of this method. The blank samples must be prepared in at least three batches on three separate calendar dates and analyzed on three separate calendar dates according to the procedures in Section 11 of this method.

8.8.2 Prepare at least seven spike samples according to the procedures in either Section 10.2 or 10.3 of this method, at a concentration of the target compound within a factor of five of the expected detection limits. The spike samples must be prepared in at least three batches on three separate calendar dates and analyzed on three separate calendar dates according to the procedures in Section 11 of this method.

8.8.3 Compute the standard deviation for the replicate blank samples concentrations and multiply this value by 3.14 to determine the blank MDL (MDLb).

8.8.4 Compute the standard deviation for the replicate spike sample concentrations and multiply this value by 3.14 to determine the spike MDL (MDLs).

8.8.5 Select the greater of MDLb or MDLs as the MDL for the compound of interest. The results must demonstrate that the method is able to detect analytes such as ethylene oxide at concentrations less than 20 pptv and at least 1/10th of the lowest concentration of interest (*i.e.,* action-level), whichever is larger. If the MDL does not meet the concentration requirement, perform corrective action and repeat the MDL determination.

8.8.6 MDL determinations must be repeated at least annually or whenever significant changes have been made to the sampling or analytical system.

Note: *The MDL calculation is based on single-tailed 99th percentile t static at six degrees of freedom. Additional blank or spike samples would increase the degrees of freedom.*

9.0 Quality Control

Table 9–1 in this section lists the quality control (QC) parameters and performance specifications for this method.

9.1 Second Source Calibration Verification (SSCV) Standard.

9.1.1 Prepare a humidified SSCV standard in a canister at a concentration in the lower third of the calibration curve. The SSCV standard must contain all compounds in the calibration mixture. The SSCV standard must be prepared independently from the calibration standards using a certified secondary source calibration standard.

9.1.2 Analyze the SSCV after the initial calibration (ICAL). Recovery of each target oHAP in the SSCV standard must be within ±30% of the theoretical concentration.

9.2 Continuing Calibration Verification (CCV) Standard. Prepare a humidified CCV standard as a dilution of a certified standard in a canister at a concentration in the lower third of the calibration curve. This certified standard must be prepared from the same standard used for the ICAL standards.

9.2.1 Analyze a CCV for each target oHAP prior to analyzing samples, after every 10 sample injections, and at the end of the analytical sequence. Prepare a humidified CCV standard as a dilution of a certified standard in a canister at a concentration in the lower third of the calibration curve. This certified standard must be prepared from the cylinder used for the ICAL standards.

9.2.2 The internal standard (IS) area responses for each CCV standard must meet the criteria outlined in Section 10.8.1.5 of this method, and the quantitated concentrations of the target compounds for each CCV standard must be within ±30% of the theoretical concentrations as determined using Equation 4 in Section 12 of this method.

9.2.3 If the CCV is not within specifications, you must invalidate any results after the last successful CCV. You must investigate and address CCV failures and initiate corrective actions, including, for example, reanalyzing the CCV, preparing and analyzing a new CCV or standard canister, and performing a new ICAL.

9.3 Blank Analyses. Analysis of all blanks must demonstrate each target compound is <20 pptv 14.7 psia or undetected (whichever is more stringent) per compound of interest. Unless otherwise stated, the volume used for analysis of blanks must match the volume of sample to be analyzed.

9.3.1 Instrument Blanks (IB). Analyze an IB at the beginning of the sequence and prior to analysis of the ICAL standard and daily CCV standard.

9.3.2 Method Blanks (MB). Analyze a laboratory MB prior to and following the ICAL in an ICAL sequence and prior to analyzing the CCV standard. The MB consists of a canister filled with humidified (40 to 50% RH) clean diluent gas and is analyzed via the same instrument method as the standards and field samples in the analytical sequence. Your MB must be the same diluent used for sample dilution.

9.3.3 Canister Field Blank. Analyze the canister field blank as part of the same analytical sequence as the accompanying field samples.

9.3.4 Calibration Blank (CB). Analyze the CB when the ICAL is established and when preparing any new CCV standard using the same instrument method that was used for standards and field samples when establishing the ICAL. The CB consists of a canister filled with the humidified (40 to 50% RH) clean diluent gas sourced through the dilution system employed to prepare standards. For laboratories that do not employ a dynamic or automated static dilution system, the CB consists of a humidified (40 to 50% RH) canister of the gas used to dilute the calibration standard.

9.4 Duplicate samples must be analyzed and reported as part of this method. They are used to evaluate sampling and/or analytical precision.

9.4.1 Field Duplicate. The level of agreement between duplicate field samples is a measure of the precision achievable for the entire sampling and analysis. Analyze the field duplicate during the same analytical sequence as the accompanying field sample. The RPD of the precision measurements should agree within ±30% when both measurements are ≥5 times the MDL. Flag associated results to indicate if the RPD indicates poor method precision.

9.4.2 Replicate Analysis. The level of agreement between replicate samples is a measure of precision achievable for the analysis. Analyze at least one replicate analysis for each set of field-collected samples. The RPD of the precision measurements should agree within ±25% when both measurements are ≥5 times the MDL. Flag associated results to indicate if the RPD indicates poor method precision.

TABLE 9–1—QUALITY CONTROL PARAMETERS AND PERFORMANCE SPECIFICATIONS

Parameter	Description and details	Required frequency	Acceptance criteria	Corrective action
Analytical zero-air verification.	Test of instrumentation to demonstrate cleanliness (positive bias) by analyzing humidified zero air; performed by connecting the clean humidified gas sample to the pre concentrator to verify that the analytical instrument and all connections are sufficiently clean.	At installation prior to initial use of the instrument.	Analysis must show that any detected target compounds in the zero-air challenge sample are at response levels that are expected to be <20 pptv or not detected.	Take steps to remove contamination attributable to the analytical instrumentation by following the manufacturer's instructions (*e.g.,* analyzing replicates of humidified clean gas).

TABLE 9–1—QUALITY CONTROL PARAMETERS AND PERFORMANCE SPECIFICATIONS—Continued

Parameter	Description and details	Required frequency	Acceptance criteria	Corrective action
Analytical known-standard challenge for analytical instrumentation.	Test to demonstrate that the analytical instrumentation (preconcentrator and GC–MS system) is not causing loss of compounds (negative bias).	At installation prior to initial use of the instrument and with instrument's annual calibration.	Verifies that all target compounds are detected by the system, that they respond consistently upon repeated injection, and that they exhibit sufficient response to be quantifiable at low concentrations (see Section 8.2.2 of this method).	Check for cold spots in transfer line, gas impurities, sorbent traps, GC column, system leaks, and/or poor moisture management. Consult instrument manufacturer for steps to eliminate bias, as necessary.
Zero-air challenge of autosamplers associated with analytical instrument systems.	After establishing the ICAL, each port of the autosampler is tested to demonstrate cleanliness (positive bias) by analyzing humidified zero air; performed by connecting the clean humidified gas sample to the port to verify that transfer lines and all connections are sufficiently clean.	Prior to initial use, upon replacement of transfer lines, or after analysis of potentially contaminating samples.	Each target VOC's concentration must be <20 pptv or preferably not detected (see Section 8.2.3 of this method).	(1) Heat and purge any lines, and/or (2) Rinse with deionized water, dry, and purge any lines that fail.
Known-standard challenge of autosamplers associated with analytical instrument systems.	After establishing the ICAL, each port of the autosampler is tested with a reference standard (approximately 100 to 500 pptv) to demonstrate that the autosampler is not causing bias (typically loss of compounds or negative bias).	Prior to initial use and upon replacement of transfer lines.	Each target VOC's concentration within ±15% of theoretical concentration (see Section 8.2.3 of this method).	(1) Heat and purge any lines, and/or (2) Rinse with deionized water, dry, and purge any lines that fail.
Canister leak check ...	Verification that canisters are leak-free by performing a pressure decay test of a canister pressurized to approximately 203 kPa absolute (29.4 psia) over the course of two days.	Prior to initial use and annually thereafter.	A pressure change ≥0.69 kPa/day (see Section 8.3.2 of this method).	(1) Remove from service, and (2) Repair canister connections and/or valve.
Canister zero-air verification.	Test of canisters to determine that they are and remain acceptably clean (show acceptably low positive bias) over the course of 7 days, by filling with humidified zero air (not nitrogen).	Initially upon receipt in the laboratory and every 18 months thereafter.	Upon initial analysis after a minimum of 24 hours and after 7 days, each target VOC's concentration ≤20 pptv at 152 kPa absolute (22.1 psia).	(1) Clean and retest canisters that fail the zero-air verification. (2) Remove canisters from service that cannot pass the zero-air verification after the cleaning process.
Known-standard challenge of canisters for qualification.	Test of canisters to determine bias by filling with a known reference standard (approximately 100 to 500 pptv) prepared in humidified zero air (not nitrogen) and analyzing.	Initially upon receipt in the laboratory and every 18 months thereafter.	Upon initial analysis after a minimum of 24 hours and subsequent analysis at 30 days or typical laboratory holding time, each target VOC's concentration must remain within ±30% of theoretical concentration (see Section 8.3.4 of this method).	(1) Clean and retest canisters that fail the zero-air verification. (2) Remove canisters from service that cannot pass the zero-air verification after the cleaning process.
Zero-air challenge of sampling devices.	Assessment of positive bias of sampling system by collecting humidified zero air through the sampling device/system and comparing it to the reference sample collected upstream of the sampling device/system.	Prior to initial field deployment and every twelve months thereafter, following maintenance (component replacement), or after collection of potentially contaminating samples.	Analysis must show that the target compounds in the zero-air challenge sample collected through the sampling unit are not >20 pptv higher than the concentration in the reference sample (see Section 8.1.5 of this method).	(1) Take steps to remove the contamination attributable to the sampling unit (*e.g.,* purging with HCF zero air overnight or longer). (2) Disassemble and clean. See Section 8.6 of this method.
Flow control flow check.	Verification of the mechanical flow control device (MFCD) flow rate.	Prior to and after each field sampling event	Flow measurement must demonstrate that the MFCD flow rate is within ±10% of the calibrated flow setting.	(1) Recalibrate or use a different MFCD for the sampling event as appropriate. (2) Flag any sample(s) collected with a failing post-flow control flow check.
Known-standard challenge of sampling devices/systems.	Assessment of bias of sampling system by collecting a known reference standard (approximately 100 to 500 pptv) through the sampling device/system and comparing it to the reference standard collected upstream of the sampling device/system.	Prior to initial field deployment and at least every twelve months thereafter, following maintenance (component replacement), or after collection of potentially contaminating samples or damaging sample matrices that may impact the activity of the flow path surfaces.	Each target VOC's concentration within ±15% of concentrations in the reference sample.	(1) Take steps to remove the contamination attributable to the sampling unit (*e.g.,* purging with HCF zero air overnight or longer). (2) Disassemble and clean. See Section 8.6 of this method.
Purge gas check	Analysis of canister cleaning purge gas to ensure contaminants are acceptably low.	Verified upon initial setup and in the event of changes in gas sourcing or after the replacement of scrubbers such as hydrocarbon traps and moisture traps, or following maintenance of zero-air generator.	Each target VOC's concentration <20 pptv (see Section 8.4.1 of this method).	Replace hydrocarbon trap, catalytic oxidizer, contaminated tubing, etc.

TABLE 9–1—QUALITY CONTROL PARAMETERS AND PERFORMANCE SPECIFICATIONS—Continued

Parameter	Description and details	Required frequency	Acceptance criteria	Corrective action
Canister cleaning blank check.	Analysis of a sample of humidified diluent gas in a canister after cleaning to ensure acceptably low levels of VOCs in the cleaned canisters.	Every canister from each batch of cleaned canisters.	Upon analysis 24 hours after filling, each target VOC's concentration must meet the canister blank acceptance criterion .(*i.e.,* ≤20 pptv at 152 kPa absolute, 22.1 psia) (see Section 8.5 of this method).	(1) Reclean canister, and/or (2) Disassemble and clean the components according to Section 8.6 of this method.
Holding time	Duration from end of sample collection or canister preparation to analysis.	Each field-collected or laboratory QC (standard or blank) canister.	≤8 days	(1) Reprepare any lab standard or blank. (2) Flag the results of any sample analyzed outside of holding time.
Bromofluorobenzene instrument tune performance check.	Injection of 1 to 2 nanograms (ng) BFB for tune verification of quadrupole or ion trap MS detector.	Prior to ICAL and prior to analysis of each day's analytical batch.	Abundance criteria for BFB listed in Table 5 in Section 17 of this method (see Section 10.7.2 of this method)	(1) Retune, and/or (2) Perform maintenance.
Retention time (RT) ...	RT of each IS and target compound.	All qualitatively identified compounds and internal standards.	IS compounds and target oHAP within ±2 seconds of most recent calibration check.	Flag data for possible invalidation.
Samples—internal standards (IS).	Deuterated or other compounds not typically found in ambient air co-analyzed with samples to monitor instrument response and assess matrix effects.	All laboratory QC samples, and field-collected samples.	Area response for each IS compound must be within ±30% of the average response as determined from the most recent calibration check.	Flag data for possible invalidation.
Initial calibration (ICAL).	Analysis of a minimum of five calibration levels covering approximately 20 to 5000 pptv.	Before sample analysis, following failed BFB tune check (as applicable), failed IS criteria, or failed CCV criteria; annually, or when changes/maintenance to the instrument affect calibration response.	Average Relative Response Factor (RRF) ≤30% RSD and each calibration level within ±30% of theoretical concentration; Relative Retention Times (RRTs) for target peaks within 0.06 units from mean RRT.	(1) Repeat calibration standard analysis. (2) Repeat linearity check. (3) Prepare new calibration standards as necessary and repeat analysis.
Second source calibration verification (SSCV).	Analysis of a secondary source standard in the lower third of the calibration curve to verify ICAL accuracy for each target analyte.	Immediately after each ICAL.	Measured concentrations of VOCs must be within ±30% of theoretical concentration (see Section 9.1 of this method).	(1) Repeat SSCV analysis. (2) Reprepare and reanalyze SSCV standard.
Continuing calibration verification (CCV).	Analysis of a known standard in the lower third of the calibration curve to verify ongoing instrument calibration for each target analyte.	Prior to analyzing samples in an analytical sequence and at the end of a sequence, unless the sequence begins with an ICAL; and after every 10 sample injections.	Measured concentrations of VOCs within ±30% of theoretical concentration (see Section 9.2 of this method).	(1) Repeat CCV analysis. (2) Repeat ICAL.
Instrument blank (IB)	Analysis of an injection where no sample or standard is introduced to the preconcentrator to preliminarily demonstrate the carrier gas and instrument are sufficiently clean to begin analysis.	Prior to ICAL and at the beginning of an analytical sequence.	Each target VOC's concentration must be <20 pptv (see Section 9.3.1 of this method).	(1) Repeat IB analysis. (2) Bakeout preconcentrator system and repeat IB analysis. (3) Replace contaminated tubing/traps as needed.
Method blank (MB)	Canister filled with clean, humidified diluent gas; indicates that target VOCs and potential interferences are at acceptably low levels in the system as a whole; the MB is to help assess overall quality of the data.	Prior to and following the ICAL and daily following the IB/BFB and prior to the initial daily CCV/SSCV.	This must demonstrate acceptably low carryover in the analytical system prior to analysis of samples; each target VOC's concentration must be <20 pptv (see Section 9.3.2 of this method).	(1) Repeat analysis. (2) Reprepare the MB canister and reanalyze. (3) Check the system for leaks.
Calibration blank (CB)	Canister filled with clean, humidified diluent gas sourced through the standard preparation dilution system; indicates that diluent gas and dilution apparatus do not contribute target VOCs, imparting a positive bias to the ICAL	Prepare one CB with each set of calibration standard canisters and analyze with each ICAL	CB must be sufficiently clean such that little or no positive bias is imparted to the calibration (see Section 9.3.3 of this method).	(1) Reanalyze CB. (2) Reprepare CB and ICAL canister standards.
Method precision	Duplicate samples: precision is determined from the analyzed concentrations of collocated samples.	Applicable to the collection of samples: one per sampling day.	Precision ≤30% RPD of target VOCs in the compared samples when both measurements are ≥ fivefold MDL (see Section 9.4 of this method).	(1) Check for preconcentrator volume measurement error. (2) Reanalyze primary sample and collocated duplicate. (3) Flag data for possible invalidation.
Instrument precision ..	Precision is determined from repeated analyses of a sample from a single canister; replicate analyses are used to determine precision of the analysis processes and do not provide information on sampling precision.	One replicate analysis to be performed with each sampling day.	Precision ≤25% RPD for target VOCs when both measurements are ≥ fivefold MDL (see Section 9.4 of this method).	(1) Check for preconcentrator volume measurement error. (2) Reanalyze primary sample and collocated duplicate. (3) Flag data for possible invalidation.

TABLE 9–1—QUALITY CONTROL PARAMETERS AND PERFORMANCE SPECIFICATIONS—Continued

Parameter	Description and details	Required frequency	Acceptance criteria	Corrective action
Preconcentrator leak check.	Pressurize or evacuate the canister connection to verify as leak-free.	Each canister connected to the instrument prior to analysis.	<3.4 kPa (0.5 psi) change per minute or as recommended by the manufacturer (see Section 11.4.2 of this method).	Check the tightness of all fittings and recheck.

10.0 Calibration and Standardization

10.1 Humidification of Canisters.

10.1.1 Calculate the volume of water you must add to standard and blank canisters to achieve 40 to 50% RH at ambient laboratory temperature. (See Equation 6 in Section 12 of this method).

10.1.2 Use a bubbler or impinger within the dilution gas stream, add water to the canister, or use a combination of these two methods to add the calculated volume of deionized water to the canister necessary to achieve internal RH of approximately 40 to 50% at ambient laboratory temperature. For direct injection of water into a canister with a syringe, install a high-pressure PTFE-sealed septum on the canister. For canisters that are to be connected to a gas source for pressurization via a dynamic or static dilution system, you can add the deionized water to the valve opening of the evacuated canister prior to connecting to the dilution system. Do not add water to the canister using a syringe via rubber septum or other materials that may introduce target or interfering compounds.

10.2 Dynamic Dilution.

10.2.1 Gas Dilution System. The gas dilution system must produce calibration gases whose measured concentration values are within ±2% of the predicted values. The predicted values are calculated based on the certified concentration of the supply gas (Protocol gases, when available, are recommended for their accuracy) and the gas flow rates (or dilution ratios) through the gas dilution system.

10.2.2 The gas dilution system must be calibrated and verified per Section 6.10.1 of this method.

10.2.3 Standards Preparation by Dynamic Dilution.

10.2.3.1 Prior to use, power on the dynamic dilution system and allow the diluent and stock gases to flow through the respective MFC at operating flow rates. Allow gases to flow for at least the minimum time used during the yearly bias check in Section 6.10.1.3 of this method, to ensure the concentrations of the oHAPs in the blended gas are stable prior to transferring to the humidified canister (or directly to the preconcentrator).

10.2.3.2 You must prepare humidified (40 to 50% RH) standards in canisters from low concentration to high concentration. When changing stock gas flow rate(s) to prepare a different concentration, allow the calibration gas sufficient time to flow through the system prior to preparation of the working calibration canister (or delivering the working standard directly to the preconcentrator).

10.2.3.3 The final pressure of the calibration standard canister must not exceed the maximum pressure permitted by the preconcentrator.

10.2.2.4 Calculate the final concentration of the diluted standard using Equation 7 in Section 12 of this method.

10.3 Static Dilution.

10.3.1 Static Gas Dilution System. The gas dilution system shall produce calibration gases whose measured values are within ±2% of the predicted values. The predicted values are calculated based on the certified concentration of the supply gases (Protocol gases, when available, are recommended for their accuracy) and their partial pressure measurements (or dilution ratios) in the prepared standard canister.

10.3.2 Static Dilution by Addition of Partial Pressures into a Canister.

10.3.2.1 Connect a pressure transducer or gauge to an evacuated canister to monitor the canister pressure as you add gases. The pressure transducer or gauge must meet the requirements in Section 6.5 of this method.

10.3.2.2 Add stock and diluent gases separately through a manifold or by direct connection of the gas to the standard canister or vessel.

10.3.2.3 Measure the canister pressure before and after standard and diluent gases are bled into the canister and input these pressures into the calculation of the dilution factor and final concentrations.

10.3.2.4 Calculate the final concentration of each target compound in the diluted standard using Equation 8 in Section 12 of this method.

10.4 Storage of Standards. Standards prepared in canisters at ambient laboratory conditions must be stored in locations that are free of potential contaminants for up to 7 days.

10.5 Pre-Concentration System Operation. Condition preconcentrator traps when first installed to eliminate contaminants that act as interferences or chromatographic artifacts, per manufacturer recommendation. After the recommended conditioning procedure is completed, analyze the IBs and MBs to verify the preconcentrator system meets the method criteria.

Note: *For preconcentrator traps that contain multiple types of sorbent beds, the oven temperature must not exceed the lowest conditioning temperature of the sorbents contained in the trap.*

10.6 GC–MS System. Optimize GC conditions for compound separation and sensitivity as indicated by baseline separation for the targeted compounds by establishing GC carrier gas flow rates, oven temperature program, and instrument run time based on the manufacturer's recommendations and customize, as needed, to separate the desired target oHAPs.

10.7 MS Tuning/Optimizing and Verification.

10.7.1 General. Tune/optimize the MS (quadrupole, ion trap, or TOF MS) to demonstrate acceptable performance across the selected ion mass range according to the manufacturer's specifications upon initial installation of the instrument and following significant preventive maintenance or repair activities that impact the performance of the GC–MS system (*e.g.,* cleaning the ion source or analyzer; trimming or replacing the capillary column; and adjusting MS tune or optimization parameters).

10.7.2 BFB Tuning Check. Before the ICAL and at least once during every 24-hour period of analyzing samples, blanks, or calibration standards thereafter, you must conduct a BFB tuning check for linear quadrupole or ion trap MS instruments. The BFB tuning check may be combined with the IB.

10.7.2.1 Introduce 1 to 2 ng of BFB into the preconcentrator and analyze the standard using the preconcentrator parameters established and used for the analysis of calibration standards, QC samples, and field samples. You must also use the method integration and analysis parameters employed for routine analysis of standards, QC samples, and field samples.

10.7.2.2 The BFB tuning check must show that the GC–MS system meets the mass spectral ion abundance criteria listed in Table 2 in Section 17 of this method for the target compounds before you can use the system for any analysis. If the GC–MS system cannot meet the BFB tuning criteria, adjust the tuning of the MS or take corrective actions. You must not use this system until the abundance criteria has been met.

10.8 Internal Standards and Calibration.

Method users must meet acceptance criteria for the calibration and QC listed in the following section for the suite of target compounds.

10.8.1 Selection and Use of Internal Standards (IS).

10.8.1.1 Select IS compound(s) to be used for oHAP analysis. At a minimum, you must use a single IS compound. IS compounds must have similar retention times to the compounds being detected. Typical IS compounds include bromochloromethane; 1,4-difluorobenzene; chlorobenzene-d5; 1,2-dichloroethane-d4; hexane-d14; toluene-d8; and 1,2-dichlorobenzene-d4.

10.8.1.2 If using purchased IS stock gases, evaluate the IS upon receipt for the presence of contaminants that may interfere with the quantitation of target compounds by analyzing increasing volumes of the IS (*e.g.,* 25, 50, 100, 250 milliliters [mL]) and examining the results for compound contaminants whose responses increase proportionally with the increasing volume of IS analyzed. Do not use IS gas standards that fail the MB acceptance criteria.

10.8.1.3 You must add the IS through a dedicated non-sample port in the preconcentrator at the same concentration for each injection (*e.g.,* standard, sample, blank) to monitor instrument sensitivity and assess potential matrix effects. Choose the concentration of IS added to each injection such that the peak area response for the IS compound approximates the area responses for target compounds in the lower half of the calibration curve range, but that minimally provides a peak that is on scale and does not exceed the area response of the highest calibration standard.

10.8.1.4 Internal Standard Retention Time (RT). Each IS compound in each sample injection must be within ±2 seconds of the RT for each IS compound in the most recent calibration.

10.8.1.5 Internal Standard Response. The area response for each IS compound in each injection (*e.g.,* calibration standard, field sample, blank, CCV) must be within ±30% of the mean area response of the IS compound determined from the ICAL determined using Equation 10 in Section 12 of this method or most recent calibration check, whichever is most appropriate.

10.8.1.6 Choose the quantitation ion for each IS compound as the most abundant ion (base peak) unless there is a spectral interference from a coeluting or nearby compound or interference that impacts the quantitation of the base peak. In such cases, select another abundant ion that is distinguishable from the other compounds for quantitation.

10.8.1.7 You must invalidate then reanalyze any samples for which the IS area response differs by more than 30% from the mean IS area response.

10.8.2 Establishing Calibration. Calibrate the GC–MS initially, annually, whenever CCV standards exceed acceptance criteria, or when the system is out of control as indicated by IS responses. Prior to calibration, analyze a sufficient number of humidified (40 to 50% RH) HCF zero air blanks or humidified check standards to verify that instrument sensitivity is stable, as indicated by IS response.

10.8.2.1 Preparation for Calibration.

10.8.2.1.1 Prepare the calibration curve by preparing standards that bracket the expected concentration levels at the sampling location(s).

10.8.2.1.2 You must include at least five levels in the ICAL to approximate concentrations of target oHAPs expected at the deployment location(s), including one level within a factor of five of the detection limits of the compounds of interest, and another level within 10% of the compound specific action-level, as defined in the applicable standard.

Note: *To establish the calibration curve, the theoretical concentrations of the working calibration standards must be calculated using the certified concentration from the gas vendor or neat standard provider. Certificates of analysis for stock standard gas mixtures typically include both a nominal (or "requested") concentration (e.g., 100 ppbv) for each analyte and a certified concentration (e.g., 108 ppbv), which should be within a specified tolerance (e.g., ±10%). These tolerances may permit the certified concentration to differ from the nominal concentration by 10% to 20%, resulting in final theoretical concentration errors for the working-level standards when the nominal concentration is input into standard concentration calculations instead of the certified concentration. Calibration standards prepared with neat materials must account for the standard purity when calculating the working standard concentrations.*

10.8.2.2 Calibration Curve.

10.8.2.2.1 Following analysis of all calibration standards, prepare a calibration curve for each target analyte by determining the relative response factor (RRF) of each concentration level. Following data acquisition for the calibration standards, calculate the RRF of each target compound in each calibration level using Equation 10 in Section 12 of this method.

10.8.2.2.2 Choose the quantitation ion for each target compound as the most abundant ion (base peak) unless there is a spectral interference from a coeluting or nearby compound or interference that impacts the quantitation of the base peak. In such cases, select another abundant ion that is distinguishable from the other compounds for quantitation.

10.8.2.2.3 The %RSD of the RRFs of the ICAL levels for each target compound using Equation 17 in Section 12. The %RSD must be ≤30% for the ICAL to be considered acceptable.

10.8.2.2.4 The calculated concentration for each target compound(s) at each calibration level must be within ±30% of the theoretical concentration when quantitated against the resulting calibration curve.

11.0 Analytical Procedures

11.1 Measurement of Canister Receipt Pressure.

11.1.1 Upon receipt at the laboratory, review the sample collection information documented on the field data page and/or COC form(s) for completeness and accuracy. Compare the canister label with the sample collection data sheet and verify that the canister and sample IDs are correct.

11.1.2 Measure and record the canister pressure using a calibrated vacuum/pressure gauge or transducer. The measured canister absolute pressure must be within ±3.5 kPa (1 in. Hg or 0.5 psi) of that measured upon collection in the field. Pressure differences exceeding this criterion indicate the canister has leaked and you must flag the results as invalid.

11.2 Dilution of Canister Samples. A canister must be pressurized to provide sufficient pressure for removing an aliquot from the canister for analysis. Pressurize the canister with diluent gas to a pressure less than or equal to the final pressure of the standard gas canisters.

Note: *Minimum sample pressures will depend on the size of the canister and the capability of the preconcentrator to remove the desired aliquot of the sample and will be indicated by the instrument manufacturer.*

11.2.2 Measure the canister pressure using a calibrated vacuum/pressure gauge or pressure transducer just prior to dilution and immediately following dilution and calculate the canister dilution correction factor (DFC) from the two absolute pressure readings (see Equation 12 in Section 12 of this method).

11.2.3 You must allow diluted canisters to equilibrate for a minimum of 12 hours before analysis.

11.3 Sample Preconcentration. Draw a measured aliquot of the whole air sample (typically 100 to 1000 mL) from the sample canister by vacuum through a preconcentrator to minimize the moisture and bulk atmospheric gases (*e.g.,* oxygen, nitrogen, argon, and carbon dioxide) from the sample aliquot prior to introduction of the target compounds to the GC.

Note: *Preconcentrator instrument manufacturers will typically indicate the optimum factory default settings for the sample aliquot volume, trapping time, trapping temperature, gas flows, and additional preconcentration parameters. Adjust each of these variables as needed for the target compounds.*

11.4 Sample Analysis. You must analyze samples using the same acquisition methods you used for establishing calibration (*i.e.,* preconcentrator operation parameters, GC oven program, MS parameters, and integration methods). Field-collected samples and QC samples must be at ambient laboratory temperature for analysis. You must use approximately the same sample aliquot volume for all samples unless dilution is required. Adjustment of this sample aliquot volume requires adjustment of a dilution factor to account for the difference in relative analyzed volume, as discussed in Section 11.4.4 of this method.

11.4.1 Leak Check of Preconcentrator Connections.

11.4.1.1 Prior to beginning an analytical sequence, including an ICAL sequence, verify each canister connection as leak-free through the preconcentrator.

11.4.1.2 During the leak check, connect canisters to the autosampler or sample introduction lines and maintain the canister valves in the closed position.

11.4.1.3 Evacuate each port of the autosampler or sample introduction line and monitor for a change in pressure for 1 minute. The pressure must not change by more than 0.5 psig/minute.

11.4.1.4 If a sample line fails the leak check, implement corrective actions (*e.g.,* rechecking the tightness of all fittings) and then retest. Do not perform analysis using any canister connection that does not pass the leak check.

11.4.1.5 Following the successful leak check, evacuate all autosampler ports or sample introduction lines, open the canister valves, and document the leak check results in the analysis records.

11.4.2 Sample Introduction.

11.4.2.1 Prior to each sample analysis sequence, you must connect each sample canister to the preconcentration unit through a port and verify each canister as having a leak-free connection.

11.4.2.2 Accurately measure the sample aliquot volume for analysis by metering the sample with an MFC or with the combination of a fixed-volume vessel and a pressure transducer. Sample introduction volume measurements must be made by the same device as the calibration standards to ensure that analyzed volumes of samples and standards are consistent.

11.4.3 Analysis of Field Samples. Perform the following steps for readying the system and performing the GC–MS analytical sequence. Once these checks meet criteria (summarized in Table 9–1 of this method), verify the instrument calibration by analysis of a CCV and begin sample analysis.

11.4.3.1 Perform an air/water check of the MS prior to any analyses to ensure that the system is acceptably leak-free.

11.4.3.2 Conduct a thorough system bakeout per the manufacturer's instructions for the preconcentrator and ramp the GC column temperature.

11.4.3.3 Analyze a preliminary IB or perform the BFB instrument tuning check.

11.4.3.4 Analyze a laboratory MB to demonstrate that the system is acceptably clean and that each target compound is <20 pptv or undetected (whichever is more stringent) per compound of interest.

11.4.3.5 Analyze a CCV to verify the instrument calibration.

11.4.3.6 Analyze field samples and additional CCV standards (every 10 samples) and MBs to complete the sequence, ending with a CCV, as discussed in Section 9.2 of this method.

11.4.4 Sample Dilution. If the on-column concentration of any compound in any sample exceeds the calibration range, you must dilute the sample for reanalysis by either reducing the sample aliquot volume for an effective dilution or adding diluent gas to the sample canister to physically dilute the sample.

11.5 Compound Identification.

11.5.1 After completing data acquisition, examine each chromatogram. Chromatographic peaks for the target compounds must be appropriately resolved, and integration must not include peak shoulders or inflections indicative of a coelution. If a peak has not been integrated properly, you may choose to manually integrate the peak. If a peak has been manually integrated, you must flag the results and report how and why the peak was manually integrated.

Note: *Deconvolution techniques may be available to the operator to help resolve compound coelutions, depending on the particular instrument and chromatography software package that is in use.*

11.5.2 Identify target compounds qualitatively based on their RT and the relative abundance of their characteristic ions from the MS by satisfying the following four criteria. If any of the four criteria are not met, the compound cannot be positively identified.

Note: *Target compounds detected below the lowest calibration standard are estimated and may not be able to satisfy all four criteria.*

11.5.2.1 The RT of the compound must be within the RT window of ±2 seconds of the most recent calibration check.

11.5.2.2 The relative abundance ratio of qualifier ion response to target ion response for at least one qualifier ion must be within ±30% of the average relative abundance ratio from the ICAL.

11.5.2.3 The S:N ratio of the target and qualifier ions must be >3:1.

11.5.2.4 The target and qualifier ion peaks must be co-maximized (*i.e.,* peak apexes within one scan of each other).

11.6 Compound Quantitation. After determining the peak areas, initiate the quantitation process using the software package of choice to provide quantitative results compound using the RRF of the daily CCV for each target compound to quantitate the samples for the analytical batch.

11.6.2 Dilution Correction Factors.

11.6.2.1 Calculate an instrument dilution correction factor (DFI) if you analyzed an aliquot from the sample canister that is different from the typical analysis volume (as described in Section 11.4.4 of this method for performing effective dilution) using Equation 14 in Section 12 of this method.

11.6.2.2 Use Equation 15 in Section 12 of this method to determine the final concentration of each target compound in air by multiplying the instrument-detected concentration by the dilution factor from sample pressurization (DFC) (see Section 11.2 of this method) and the DFI.

Note: *The MDL reported with the final concentration data will be corrected by multiplying the MDL by the DFC and DFI applied to the sample concentrations.*

12.0 Data Analysis and Calculations

12.1 Canister Final Air/Nitrogen Volume (V_{calc}).

$$V_{calc} = \left(\left(\frac{P_i - P_{std}}{P_{std}}\right) * V_{can}\right) + V_{can} \quad \text{Eq. 1}$$

Where:

P_{clean} = absolute pressure of canister cleaning batch blank, kPa absolute.

P_{std} = 152.3 kPa absolute, standard atmospheric pressure.

V_{can} = volume of the canister (mL) at standard conditions (101.3 kPa absolute and 25 °C).

12.2 Acceptable Blank Canister Concentration Criterion (C_{acc}).

$$C_{acc} = C_{atm} * \left(\frac{P_{ref}}{P_{clean}}\right) \quad \text{Eq. 2}$$

Where:

C_{acc} = acceptance limit concentration at measured canister pressure (pptv).

C_{atm} = 20 pptv, acceptance limit concentration at standard atmospheric pressure.

P_{ref} = 152 kPa absolute, reference pressure.

P_{clean} = absolute pressure of cleaned canister, kPa absolute.

12.3 Percent Difference of the Measured Concentration of Each Target Compound in the CCV Standard ($\%D_{CCV}$) from the Theoretical Concentration.

$$\%D_{CCV} = \frac{C_{CCV} - C_{theoretical}}{C_{theoretical}} \times 100 \quad \text{Eq. 3}$$

Where:

$\%D_{CCV}$ = percent difference of the measured concentration of each target compound in the CCV standard from the theoretical concentration.

C_{CCV} = measured concentration of the CCV for each target compound (pptv).

$C_{theoretical}$ = theoretical concentration of the CCV for each target compound (pptv).

12.4 Percent Recovery ($\%Recovery_{CCV}$).

$$\%Recovery_{CCV} = \frac{C_{CCV}}{C_{theoretical}} \times 100 \quad \text{Eq. 4}$$

Where:

$\%Recovery_{CCV}$ = percent recovery of measured versus actual concentration.

$C_{theoretical}$ = theoretical concentration of the CCV for each target compound (pptv).

12.5 Relative Percent Difference (RPD).

$$RPD = \left|\frac{X_1 - X_2}{\left(\frac{X_1 + X_2}{2}\right)}\right| \times 100 \quad \text{Eq. 5}$$

Where:

RPD = relative percent difference.

X_1 = target compound concentration measured in first measurement of the precision pair (pptv).

X_2 = target compound concentration measured in second measurement of the precision pair (pptv).

12.6 Water Volume to Add to Canister (V_w).

$$V_w = D_{sat} \cdot RH_d \cdot V_c \cdot \frac{P_c}{P_s} \cdot \frac{1}{D_w} \quad \text{Eq. 6}$$

Where:

D_{sat} = saturation vapor density of water (mg/µL) at ambient laboratory temperature (refer to Table 3 in Section 17 of this method).

RH_d = desired RH level expressed as a decimal.

V_c = nominal internal volume of canister (L).

P_c = final absolute canister pressure (kPa absolute).

P_s = standard ambient pressure (101.3 kPa absolute).

D_w = density of water (1 mg/µL).

Note: *The equation assumes the density of water to be 1 g/mL and that 100% of the added water to the canister is in the gas phase. The equation does not correct the density of water for the ambient temperature.*

12.7 Final Concentration of the Diluted Standard (C_f)—Dynamic Dilution.

$$C_f = \frac{C_s \cdot F_s}{F_s + F_d} \qquad \text{Eq. 7}$$

Where:

C_f = final concentration of the diluted standard.

C_s = certified concentration of stock standard (pptv).

F_d = flow of diluent gas (mL/min).

F_s = flow of stock standard (mL/min).

Note: *If you combine multiple gas standards for dilution, the equation denominator is the sum of all gas flows combined for preparing the dilution.*

12.8 Final Concentration of the Diluted Standard (C_f)—Static Dilution.

$$C_f = \frac{C_s \cdot (P_{sa} - P_{sb})}{P_f} \qquad \text{Eq. 8}$$

Where:

C_s = certified concentration of stock standard (pptv).

P_{sa} = absolute pressure of canister after adding standard gas (kPa).

P_{sb} = absolute pressure of canister before adding standard gas (kPa).

P_f = final absolute pressure of canister after adding standard and diluent gases (kPa).

12.9 Average Retention Time ($\overline{RT}$).

$$\overline{RT} = \sum_{i=1}^{n} \frac{RT_i}{n} \qquad \text{Eq. 9}$$

Where:

$\overline{RT}$ = average RT for the IS compound (min).

RT_i = RT for the IS compound for each calibration level (min).

n = number of units used to generate a sum.

12.10 Relative Response Factor (RRF).

$$RRF = \frac{A_s \cdot C_{IS}}{A_{IS} \cdot C_s} \qquad \text{Eq. 10}$$

Where:

A_s = peak area for quantitation ion of the target compound.

A_{IS} = peak area for quantitation ion of the assigned IS compound.

C_s = certified concentration of stock standard (pptv).

C_{IS} = concentration of the assigned IS compound (pptv).

12.11 Average Area Response for the Given IS Compound ($\bar{Y}$).

$$\bar{Y} = \sum_{i=1}^{n} \frac{Y_i}{n} \qquad \text{Eq. 11}$$

Where:

Y_i = area response for an IS compound at calibration concentration i.

n = number of units used to generate a sum.

12.12 Dilution factor for sample pressurization (DF_C).

$$DF_C = \frac{P_d}{P_i} \qquad \text{Eq. 12}$$

Where:

P_d = pressure of the canister following dilution (kPa).

P_i = absolute pressure of the canister immediately preceding dilution (kPa).

12.13 Instrument-Detected Analyte Concentration (C_D) in pptv.

$$C_D = \frac{A_t \cdot C_{IS}}{A_{IS} \cdot RRF} \qquad \text{Eq. 13}$$

Where:

C_D = instrument-detected analyte concentration (pptv).

A_{IS} = peak area for quantitation ion of the assigned IS compound.

12.14 Instrument Dilution Correction Factor (DF_I).

$$DF_I = \frac{V_{nom}}{V_{inj}} \qquad \text{Eq. 14}$$

Where:

V_{nom} = The laboratory's typical canister sample injection volume (mL).

V_{inj} = The actual volume of any given sample injection (mL).

12.15 Concentration of the Target Compound in Air (C_F).

$$C_F = C_D \cdot DF_I \cdot DF_C \qquad \text{Eq. 15}$$

Where:

C_D = measured concentration of the target compound in the canister as analyzed sample.

12.16 Standard Deviation of the Response Factors (SD_{RF}).

$$SD_{RRF} = \sqrt{\frac{\sum_{i=1}^{n}(RRF_i - \overline{RRF})^2}{(n-1)}} \qquad \text{Eq. 16}$$

12.17 Percent Relative Deviation (%RSD).

$$\%RSD = SD_{RRF} \div \overline{RRF} \times 100 \qquad \text{Eq. 17}$$

13.0 Method Performance

Table 9–1 of this method lists the QC parameters and performance specifications for this method. The method performance will be determined by the specific performance of each specific target compound, laboratory, and the associated equipment.

14.0 Pollution Prevention

[Reserved].

15.0 Waste Management

[Reserved].

16.0 References

1. *Quality Assurance Handbook for Air Pollution Measurement Systems,* Volume II, Ambient Air Quality Monitoring Program, U.S. Environmental Protection Agency, EPA–454/B–17–001, January 2017.
2. Technical Assistance Document for the National Air Toxics Trends Stations Program, Revision 4, U.S. Environmental Protection Agency, July 2022.
3. Clean Air Act Amendments of 1990, U.S. Congress, Washington, DC, November 1990.
4. Method D1356, Standard Terminology Relating to Sampling and Analysis of Atmospheres.
5. Method E355–96, Standard Practice for Gas Chromatography Terms and Relationships.
6. Method D5466, Standard Test Method for Determination of Volatile Organic Compounds in Atmospheres (Canister Sampling Methodology).
7. Agilent Technologies, Inc. (2017, July 11). Innovative Cryogen-Free Ambient Air Monitoring in Compliance with US EPA Method TO–15. Application Note 081, 5991–2829EN. Available at *https://www.agilent.com/cs/library/applications/5991-2829EN.pdf* (accessed September 21, 2019).
8. ASTM International. (2014). Active Standard ASTM E2655–14: Standard Guide for Reporting Uncertainty of Test Results and Use of the Term Measurement Uncertainty in ASTM Test Methods. West Conshohocken, PA: ASTM International. doi: 10.1520/E2655–14.
9. Boyd, R.K., Basic, C., & Bethem, R.A. (2008). *Trace Quantitative Analysis by Mass Spectrometry,* Figure 6.7, p. 260. Hoboken, NJ: John Wiley and Sons.
10. Brown, J. (2013, October 22). Choosing the Right Adsorbent for your Thermal Desorption Gas Chromatography Applications. Presented at the Separation Science Webinar for Supelco. Available at *https://www.sigmaaldrich.com/content/dam/sigma-aldrich/docs/Supelco/Posters/1/Adsorbent-Selection-TD-GC-Apps.pdf* (accessed September 21, 2019).
11. *Code of Federal Regulations,* 40 CFR part 58 Appendices D and E, Network Design Criteria for Ambient Air Quality Monitoring. Available at *https://www.govinfo.gov/app/details/CFR-2012-title40-vol6/CFR-2012-title40-vol6-part58-appD* (accessed September 22, 2019).
12. *Code of Federal Regulations,* 40 CFR part 136 Appendix B, Definition and Procedure for the Determination of the Method Detection Limit, Revision 2. Available at *https://www.govinfo.gov/app/search/%7B%22query%22%3A%2240%20CFR%20Part%20136%20Appendix%20B%2C%20Revision%202%22%2C%22offset%22%3A0%7D* (accessed September 23, 2019).
13. *Code of Federal Regulations,* 40 CFR 173.306 (g), Limited quantities of compressed gases. Available at *https://www.govinfo.gov/app/search/%7B%22query%22%3A%2249%20CFR%20%C2%A7173.306%20(g)%22%2C%22offset%22%3A0%7D* (accessed September 23, 2019).
14. Coutant, R.W. (1992). Theoretical Evaluation of the Stability of Volatile Organic Chemicals and Polar Volatile Organic Chemicals in Canisters. Report EPA/600/R–92/055 prepared under contract 68–DO–0007 for U.S. EPA by Battelle, Columbus, OH.
15. Entech Instruments. (2015, August 25). 3-Stage Preconcentration: Why 3-Stage Preconcentration is Superior for TO–14A and TO–15 Air Methods. Available at *http://www.entechinst.com/3-stage-preconcentration-is-superior-for-to-14a-and-to-15-air-methods/#* (accessed September 21, 2019).
16. Herrington, J.S. (2013, August 5). TO–15 Canister Relative Humidity: Part II (Examples and Calculations) [Blog post]. Available at *https://blog.restek.com/?p=7766* (accessed September 21, 2019).
17. Keith, L.H. (1991). *Environmental Sampling and Analysis: A Practical Guide.* Boca Raton, FL: CRC Press, pp. 93–119.
18. Kelly T.J., & Holdren, M.W. (1995). Applicability of canisters for sample storage in the determination of hazardous air pollutants. *Atmospheric Environment,* 29(19), 2595–2608. doi: 10.1016/1352–2310(95)00192–2.
19. McClenny, W.A., Schmidt, S.M., & Kronmiller, K.G. (1999). Variation of the relative humidity of air released from canisters after ambient sampling. *Journal of the Air & Waste Management Association,* 49(1), 64–69. doi:10.1080/10473289.1999.10463774.
20. Nave, C.R. (2017). Relative Humidity. HyperPhysics website, Department of Physics and Astronomy, Georgia State University, Atlanta, GA. Available at *http://hyperphysics.phy-astr.gsu.edu/hbase/Kinetic/relhum.html#c3* (accessed September 21, 2019).
21. Ochiai, N., Daishima, S., & Cardin, D.B. (2003). Long-term measurement of volatile organic compounds in ambient air by canister-based one-week sampling method. *Journal of Environmental Monitoring,* 5(6), 997–1003. doi:10.1039/b307777m.
22. Ochiai, N., Tsuji, A., Nakamura, N., Daishima, S., & Cardin, D.B. (2002). Stabilities of 58 volatile organic compounds in fused-silica-lined and SUMMA polished canisters under various humidified conditions. *Journal of Environmental Monitoring,* 4(6), 879–889.
23. Restek. (2010). A Guide to Whole Air Canister Sampling: Equipment Needed and Practical Techniques for Collecting Air Samples. Technical Guide. Literature Catalog # EVTG1073A. Available at *http://www.restek.com/pdfs/EVTG1073A.pdf* (accessed September 21, 2019).
24. U.S. Environmental Protection Agency (EPA). (2017). *Quality Assurance Handbook for Air Pollution Measurement Systems,* Volume II, Ambient Air Quality Monitoring Program, EPA–454/B–17–001. Research Triangle Park, NC: EPA Office of Air

Quality Planning and Standards, Air Quality Assessment Division. Available at *https://www3.epa.gov/ttnamti1/files/ambient/pm25/qa/Final%20Handbook%20Document%201_17.pdf* (accessed September 23, 2019).

25. U.S. Environmental Protection Agency (EPA). (2016a). Definition and Procedure for the Determination of the Method Detection Limit, Revision 2. U.S. EPA Office of Water, EPA 821–R–16–006. Available at *https://www.epa.gov/sites/production/files/2016-12/documents/mdl-procedure_rev2_12-13-2016.pdf* (accessed September 21, 2019).
26. U.S. Environmental Protection Agency (EPA). (2016b). EPA NATTS Proficiency Testing Results Calendar Year 2016 Quarter 1—Referee Results from EPA Region V. Available from U.S. EPA, Office of Air Quality Planning and Standards (OAQPS), Ambient Air Monitoring Group, Mail Code C304–06, Research Triangle Park, NC 27711.
27. U.S. Environmental Protection Agency (EPA). (2015). OSWER Technical Guide for Assessing and Mitigating the Vapor Intrusion Pathway from Subsurface Vapor Sources to Indoor Air. EPA Office of Solid Waste and Emergency Response (OSWER) Publication 9200.2–154. Available at *https://www.epa.gov/vaporintrusion/technical-guide-assessing-and-mitigating-vapor-intrusion-pathway-subsurface-vapor* (accessed September 22, 2019).
28. Wang, D.K., & Austin, C.C. (2006). Determination of complex mixtures of volatile organic compounds in ambient air: canister methodology. *Analytical and Bioanalytical Chemistry,* 386(4), 1099–1120. doi:10.1007/s00216–006–0466–6.
29. Batelle. (2016). Technical Assistance Document for the National Air Toxics Trends Stations Program, Revision 3. Prepared for U.S. EPA by Battelle, Columbus, OH. Available at *https://www3.epa.gov/ttn/amtic/files/ambient/airtox/NATTS%20TAD%20Revision%203_FINAL%20October%202016.pdf* (accessed September 22, 2019).
30. Daughtrey, E.H. Jr., Oliver, K.D., Jacumin, H.H. Jr., & McClenny, W.A. (2004, April 20–22). Supplement to EPA Compendium Method TO–15—Reduction of Method Detection Limits to Meet Vapor Intrusion Monitoring Needs. Presented at Symposium on Air Quality Measurement Methods and Technology, Research Triangle Park, NC. Available at *https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=NERL&dirEntryId=76137* (accessed September 22, 2019).
31. Entech Instruments. (2019). Articles and documents. Available at *https://www.entechinst.com/technical-library/application-notes-applets-chromatograms/* (accessed September 23, 2019).
32. Kelly, T., Gordon, S., Mukund, R., & Hays, M. (1994). Ambient Measurement Methods and Properties of the 189 Clean Air Act Hazardous Air Pollutants. Report EPA/600/R–94/187 prepared under contract 68–DO–0007, work assignment 44, for U.S. EPA by Battelle, Columbus, OH.
33. Kelly, T.J., Callahan, P.J., Pleil, J., & Evans, G.F. (1993). Method development and field measurements for polar volatile organic compounds in ambient air. *Environmental Science & Technology,* 27(6), 1146–1153.
34. McClenny, W.A., Oliver, K.D., & Daughtrey, E.H. Jr. (1995). Analysis of VOCs in ambient air using multisorbent packings for VOC accumulation and sample drying. *Journal of the Air & Waste Management Association,* 45(10), 792–800.
35. Morris, C., Berkley, R., & Bumgarner, J. (1983). Preparation of multicomponent volatile organic standards using static dilution bottles. *Analytical Letters,* 16(20), 1585–1593.
36. Oliver, K.D., Adams, J.R., Daughtrey, E.H., McClenny, W.A., Yoong, M.J., Pardee, M.A., Almasi, E.B., & Kirshen, N.A. (1996). Technique for monitoring toxic VOCs in air: Sorbent preconcentration, closed-cycle cooler cryofocusing, and GC/MS analysis. *Environmental Science & Technology,* 30(6), 1939–1945.
37. Pleil, J.D., & Lindstrom, A.B. (1995). Collection of a single alveolar exhaled breath for volatile organic compound analysis. *American Journal of Industrial Medicine,* 28(1), 109–121.
38. Pleil, J.D., McClenny, W.A., Holdren, M.W., Pollack, A.J., & Oliver, K.D. (1993). Spatially resolved monitoring for volatile organic compounds using remote sector sampling. *Atmospheric Environment, Part A,* 27(5), 739–747.
39. Pollack, A.J., Holdren, M.W., & McClenny, W.A. (1991). Multi-adsorbent preconcentration and gas chromatographic analysis of air toxics with an automated collection/analytical system. *Journal of the Air & Waste Management Association,* 41(9), 1213–1217.
40. Restek. (2019). Restek Technical Library: Air Sampling. Available at *https://www.restek.com/Technical-Resources/Technical-Library/Air-Sampling* (accessed September 23, 2019).
41. Stephenson, J., Allen, F., & Slagle, T. (1990). Analysis of volatile organics in air via water methods. In *Proceedings of the 1990 EPA/AWMA International Symposium: Measurement of Toxic and Related Air Pollutants,* EPA 600/9–90–026. Research Triangle Park, NC: U. S. Environmental Protection Agency.
42. U.S. Environmental Protection Agency (EPA). (1997). Method TO–14A: Determination of volatile organic compounds (VOCs) in ambient air using specially prepared canisters with subsequent analysis by gas chromatography, EPA 600/625/R–96/010b. In *Compendium of Methods for the Determination of Toxic Organic Compounds in Ambient Air,* Second Edition. Cincinnati, OH: U.S. EPA Center for Environmental Research Information, Office of Research and Development.
43. Whitaker, D.A., Fortmann, R.C., & Lindstrom, A.B. (1995). Development and testing of a whole-air sampler for measurement of personal exposure to volatile organic compounds. *Journal of Exposure Analysis & Environmental Epidemiology,* 5(1), 89–100.

17.0 Tables, Diagrams, Flow Charts, etc.

TABLE 1—CANISTER CLEANING PARAMETERS

Canister type	Pre-evacuate canister	Suggested maximum canister temperature [a]	Humidity	Minimum number of pressure/evacuation cycles	Cycle time
All	Yes	80 °C	50%	5	Varies by system.

[a] Higher purge gas temperatures may be required depending on the canister type—do not exceed the manufacturer's recommended maximum temperatures for component parts such as valves and gauges.

TABLE 2—BFB TUNING CHECK KEY IONS AND ABUNDANCE CRITERIA

Mass	Ion abundance criteria [a]
50	8.0% to 40.0% of m/z 95.
75	30.0% to 66.0% of m/z 95.
95	Base peak, 100% relative abundance.
96	5.0% to 9.0% of m/z 95.
173	<2.0% of m/z 174.
174	50.0% to 120.0% of m/z 95.

TABLE 2—BFB TUNING CHECK KEY IONS AND ABUNDANCE CRITERIA—Continued

Mass	Ion abundance criteria [a]
175	4.0% to 9.0% of *m/z* 174.
176	93.0% to 101.0% of *m/z* 174.
177	5.0% to 9.0% of *m/z* 176.

[a] All ion abundances must be normalized to m/z 95, the nominal base peak, even though the ion abundance of m/z 174 may be up to 120% that of m/z 95.

TABLE 3—WATER SATURATION VAPOR DENSITY AT VARIOUS TEMPERATURES

Temperature (°C)	Water saturation vapor density (mg/L) [a]
15	12.8
16	13.6
17	14.4
18	15.3
19	16.3
20	17.3
21	18.3
22	19.4
23	20.6
24	21.8
25	23.1
26	24.4
27	25.9
28	27.3
29	28.9
30	30.5
31	32.2
32	34.0
33	35.8

[a] Values are generated according to the following formula (Nave, 2017): *vapor density (mg/L)* = $5.018 + 0.32321 * T + 8.1847 \times 10^{-3} * T^2 + 3.1243 \times 10^{-4} * T^3$, where: T = temperature in °C.

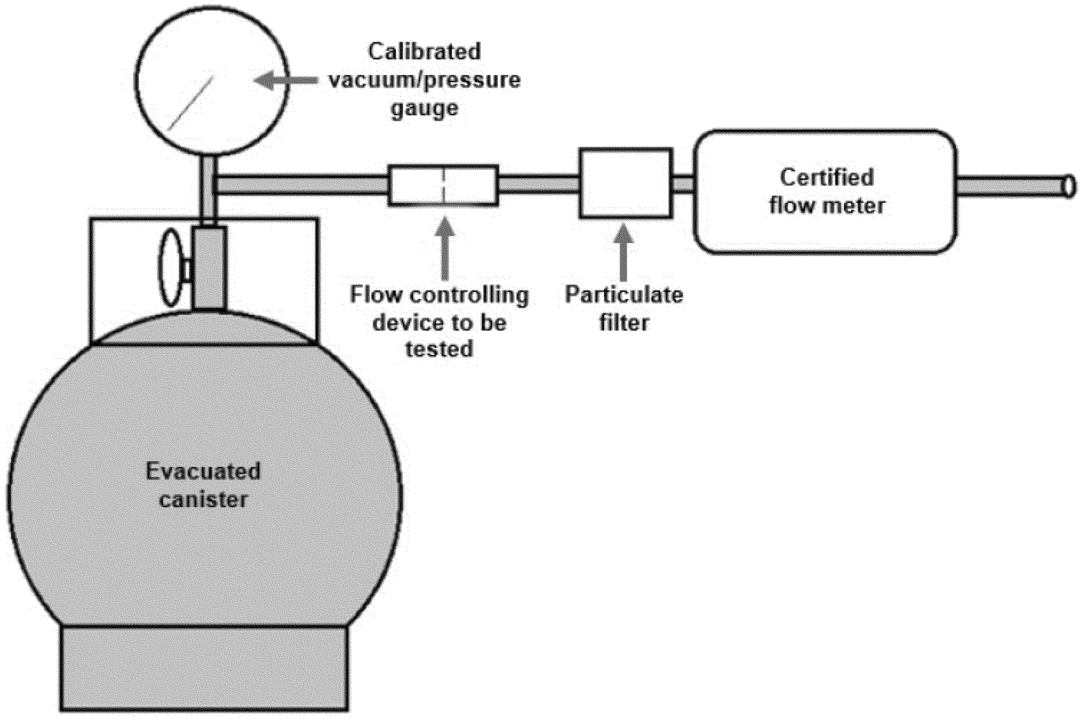


Figure 1. Apparatus for Characterizing the Flow Control Device

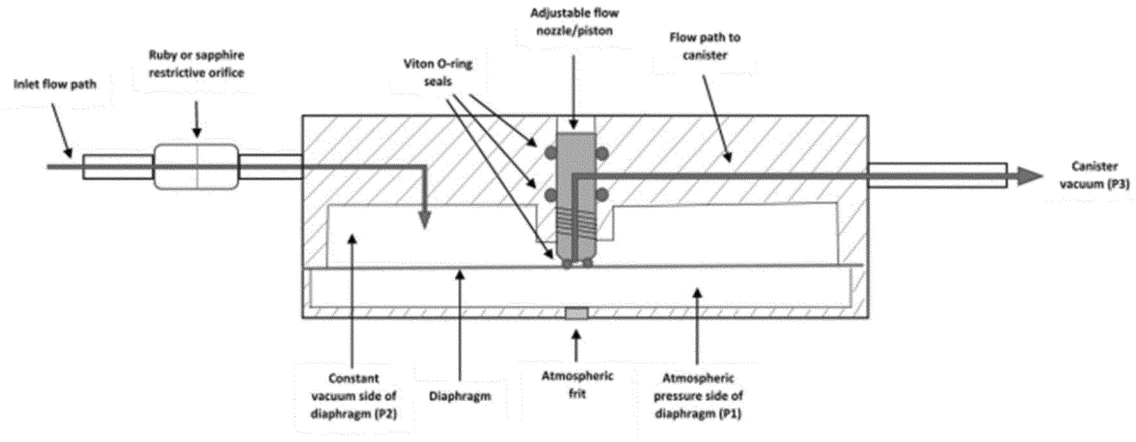


Figure 2. Mechanical Flow Control Device

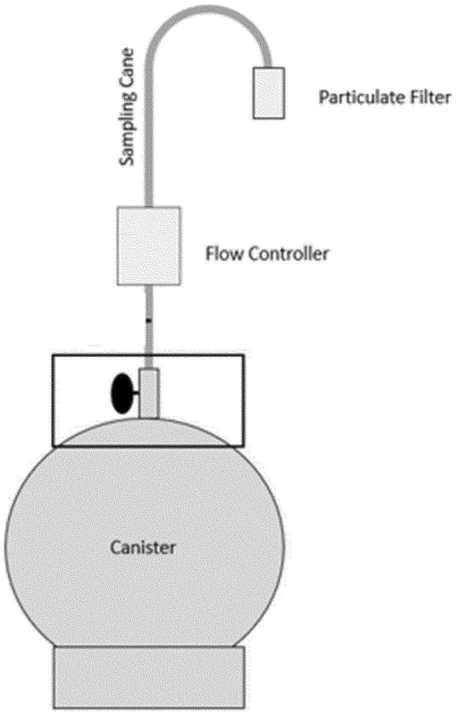
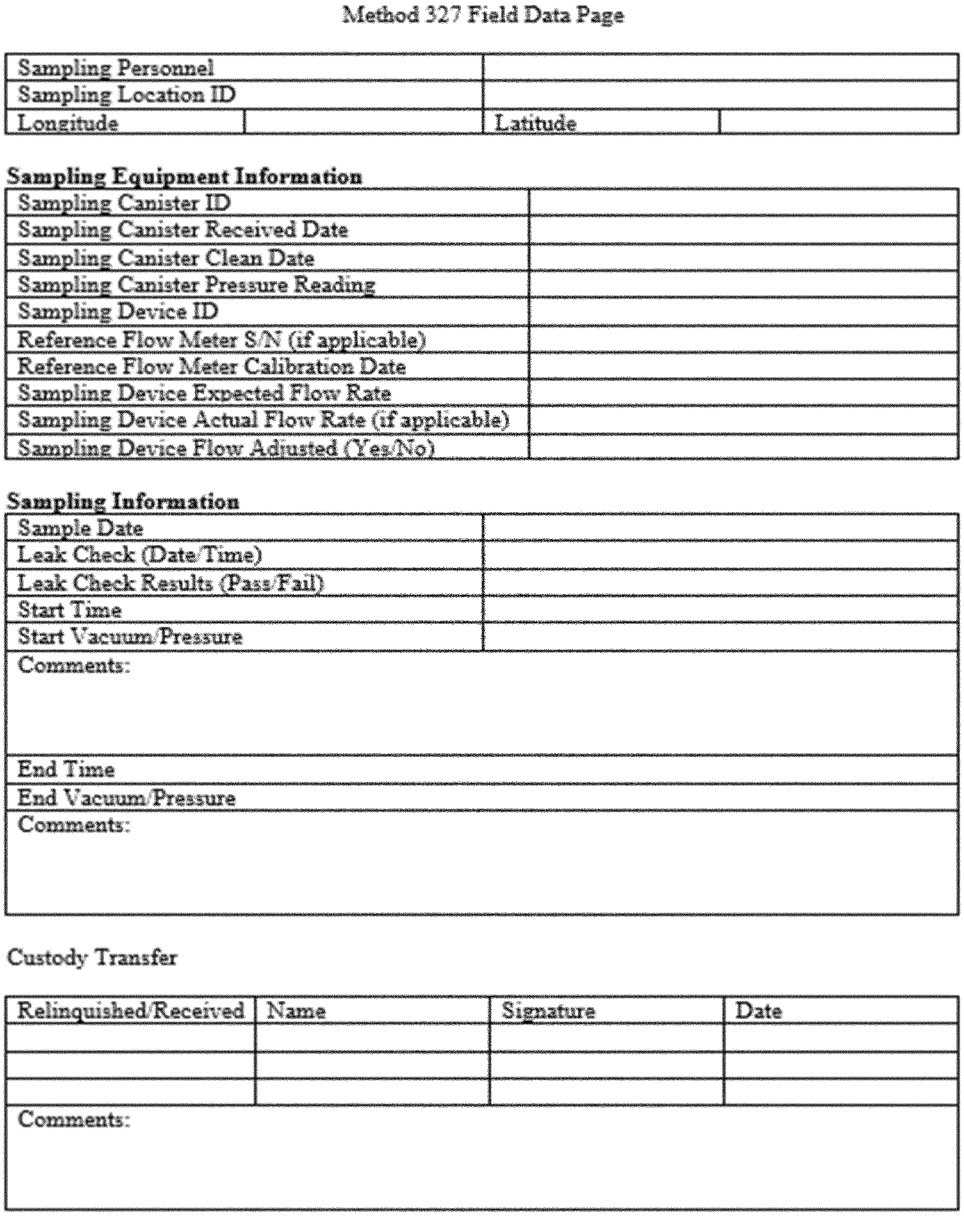


Figure 3. Method 327 Sampler



Method 327 Field Data Page

Sampling Personnel			
Sampling Location ID			
Longitude		Latitude	

Sampling Equipment Information

Sampling Canister ID	
Sampling Canister Received Date	
Sampling Canister Clean Date	
Sampling Canister Pressure Reading	
Sampling Device ID	
Reference Flow Meter S/N (if applicable)	
Reference Flow Meter Calibration Date	
Sampling Device Expected Flow Rate	
Sampling Device Actual Flow Rate (if applicable)	
Sampling Device Flow Adjusted (Yes/No)	

Sampling Information

Sample Date	
Leak Check (Date/Time)	
Leak Check Results (Pass/Fail)	
Start Time	
Start Vacuum/Pressure	
Comments:	
End Time	
End Vacuum/Pressure	
Comments:	

Custody Transfer

Relinquished/Received	Name	Signature	Date
Comments:			

Figure 4. Example Field Data Page

[FR Doc. 2024–07002 Filed 5–15–24; 8:45 am]

BILLING CODE 6560–50–P

affected facility (*e.g.,* large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the *force majeure* event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 5. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart R—National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

■ 6. Section 63.420 is amended by

■ a. Revising paragraphs (a) introductory text, (a)(1) introductory text, (a)(2), (b) introductory text, (b)(1) introductory text, (b)(2), (c) introductory text, (c)(2), (d) introductory text, (d)(2), (g), (i), and (j); and

■ b. Adding paragraph (k).

The revisions and addition read as follows:

§ 63.420 Applicability.

(a) Prior to May 8, 2027, the affected source to which the provisions of this subpart apply is each bulk gasoline terminal, except those bulk gasoline terminals meeting either of the criteria listed in paragraph (a)(1) or (2) of this section. No later than May 8, 2027, the affected source to which the provisions of this subpart apply is each bulk gasoline terminal located at a major source as defined in § 63.2.

(1) Bulk gasoline terminals for which the owner or operator has documented and recorded to the Administrator's satisfaction that the result, E_T, of the following equation is less than 1, and complies with requirements in paragraphs (c), (d), (e), and (f) of this section:

* * * * *

(2) Bulk gasoline terminals for which the owner or operator has documented and recorded to the Administrator's satisfaction that the facility is not a major source, or is not located within a contiguous area and under common control of a facility that is a major source, as defined in § 63.2.

(b) Prior to May 8, 2027, the affected source to which the provisions of this subpart apply is each pipeline breakout station, except those pipeline breakout stations meeting either of the criteria listed in paragraph (b)(1) or (2) of this section. No later than May 8, 2027, the affected source to which the provisions of this subpart apply is each pipeline breakout station located at a major source as defined in § 63.2.

(1) Pipeline breakout stations for which the owner or operator has documented and recorded to the Administrator's satisfaction that the result, E_P, of the following equation is less than 1, and complies with requirements in paragraphs (c), (d), (e), and (f) of this section:

* * * * *

(2) Pipeline breakout stations for which the owner or operator has documented and recorded to the Administrator's satisfaction that the facility is not a major source, or is not located within a contiguous area and under common control of a facility that is a major source, as defined in § 63.2.

(c) Prior to May 8, 2027, a facility for which the results, E_T or E_P, of the calculation in paragraph (a)(1) or (b)(1) of this section has been documented and is less than 1.0 but greater than or equal to 0.50, is exempt from the requirements of this subpart, except that the owner or operator shall:

* * * * *

(2) Maintain records and provide reports in accordance with the provisions of § 63.428(l)(4).

(d) Prior to May 8, 2027, a facility for which the results, E_T or E_P, of the calculation in paragraph (a)(1) or (b)(1) of this section has been documented and is less than 0.50, is exempt from the requirements of this subpart, except that the owner or operator shall:

* * * * *

(2) Maintain records and provide reports in accordance with the provisions of § 63.428(l)(5).

* * * * *

(g) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart that is also subject to applicable provisions of part 60, subpart Kb, XX, or XXa, of this chapter shall comply only with the provisions in each subpart that contain the most stringent control requirements for that facility.

* * * * *

(i) A bulk gasoline terminal or pipeline breakout station with a Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery complying with §§ 63.646, 63.648, 63.649, 63.650, and 63.660 is not subject to the standards in this subpart, except as specified in § 63.650.

(j) Notwithstanding any other provision of this subpart, the December 14, 1995, compliance date for existing facilities in §§ 63.424(e) and 63.428(a), (l)(4)(i), and (l)(5)(i) is stayed from December 8, 1995, to March 7, 1996.

(k) Each owner or operator of an affected source bulk gasoline terminal or pipeline breakout station must comply with the standards in this part at all times. 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 or 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.

■ 7. Section 63.421 is amended by:

■ a. Revising the introductory text and the definitions of ''Bulk gasoline terminal'' and ''Flare'';

■ b. Adding in alphabetical order a definition for ''Gasoline'';

■ c. Revising the definition of ''Pipeline breakout station'';

■ d. Adding in alphabetical order a definition for ''Submerged filling''; and

■ e. Revising the definition for ''Thermal oxidation system''.

The revisions and additions read as follows:

§ 63.421 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act; in subparts A, K, Ka, Kb, and Xxa of part 60 of this chapter; or in subpart A of this part. All terms defined in both subpart A of part 60 of this chapter and subpart A of this part shall have the meaning given in subpart A of this part. For purposes of this subpart, definitions in this section supersede definitions in other parts or subparts.

Bulk gasoline terminal means:

(1) Prior to May 8, 2027, any gasoline facility which receives gasoline by pipeline, ship or barge, and has a gasoline throughput greater than 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, State, or local law and discoverable by the Administrator and any other person.

(2) On or after May 8, 2027, any gasoline facility which receives gasoline by pipeline, ship, barge, or cargo tank and subsequently loads all or a portion of the gasoline into gasoline cargo tanks for transport to bulk gasoline plants or gasoline dispensing facilities and has a gasoline throughput greater than 20,000 gallons per day (75,700 liters per day). Gasoline throughput shall be the maximum calculated design throughput for the facility as may be limited by compliance with an enforceable condition under Federal, State, or local law and discoverable by the Administrator and any other person.

* * * * *

Flare means a thermal combustion device using an open or shrouded flame (without full enclosure) such that the pollutants are not emitted through a conveyance suitable to conduct a performance test.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 4.0 pounds per square inch (27.6 kilopascals) or greater, which is used as a fuel for internal combustion engines.

* * * * *

Pipeline breakout station means:

(1) Prior to May 8, 2027, 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.

(2) On or after May 8, 2027, 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 to other facilities. *Pipeline breakout stations* do not have loading racks where gasoline is loaded into cargo tanks. If any gasoline is loaded into cargo tanks, the facility is a bulk gasoline terminal for the purposes of this subpart provided the facility-wide gasoline throughput (including pipeline throughput) exceeds the limits specified for bulk gasoline terminals.

* * * * *

Submerged filling means the filling of a gasoline cargo tank through a submerged fill pipe whose discharge is no more than the 6 inches from the bottom of the tank. Bottom filling of gasoline cargo tanks is included in this definition.

Thermal oxidation system means an enclosed combustion device used to mix and ignite fuel, air pollutants, and air to provide a flame to heat and oxidize hazardous air pollutants. Auxiliary fuel may be used to heat air pollutants to combustion temperatures. *Thermal oxidation systems* emit pollutants through a conveyance suitable to conduct a performance test.

* * * * *

■ 8. Revise § 63.422 to read as follows:

§ 63.422 Standards: Loading racks.

(a) You must meet either the requirements in paragraph (a)(1) or (2) of this section, as applicable in paragraph (d) of this section.

(1) Each owner or operator of loading racks at a bulk gasoline terminal subject to the provisions of this subpart shall comply with the requirements in § 60.502 of this chapter except for paragraphs (b), (c), and (j) of that section. For purposes of this section, the term ‘‘affected facility’’ used in § 60.502 means the loading racks that load gasoline cargo tanks at the bulk gasoline terminals subject to the provisions of this subpart.

(2) Each owner or operator of loading racks at a bulk gasoline terminal subject to the provisions of this subpart shall comply with the requirements in § 60.502a of this chapter except for paragraphs (b) and (j) of that section and shall comply with the provisions in paragraphs (b) through (c) of this section. For purposes of this section, the term ‘‘gasoline loading rack affected facility’’ used in § 60.502a means ‘‘the loading racks that load gasoline cargo tanks at the bulk gasoline terminals subject to the provisions of this subpart.’’ For purposes of this subpart, the term ‘‘vapor-tight gasoline cargo tanks’’ used in § 60.502a(e) of this chapter shall have the meaning given in § 63.421. As an alternative to the pressure monitoring requirements in § 60.504a(d) of this chapter, you may comply with the requirements specified in § 63.427(f).

(b) You must meet either the emission limits in paragraph (b)(1) or (2) of this section, as applicable in paragraph (d) of this section.

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

(2) You must comply with the provisions in § 60.502a(c) of this chapter for all loading racks that load gasoline cargo tanks at the bulk gasoline terminals subject to the provisions of this subpart, not just those that are modified or reconstructed.

(c) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall discontinue loading any cargo tank that fails vapor tightness according to the test requirements in § 63.425(f), (g), and (h) until vapor tightness documentation for that gasoline cargo tank is obtained which documents that:

(1) The tank truck or railcar gasoline cargo tank has been repaired, retested, and subsequently passed either the annual certification test described in § 63.425(e) or the railcar bubble test described in § 63.425(i); or

(2) For each gasoline cargo tank failing the test in § 63.425(f) at the facility, the cargo tank meets the test requirements in either § 63.425(g) or (h); or

(3) For each gasoline cargo tank failing the test in § 63.425(g) at the facility, the cargo tank meets the test requirements in § 63.425(h).

(d) Each owner or operator shall meet the requirements in this section as expeditiously as practicable, but no later than the dates provided in paragraphs (d)(1) through (3) of this section.

(1) For facilities that commenced construction on or before February 8, 1994, each owner or operator shall meet the requirements in paragraphs (a)(1), (b)(1), and (c) of this section no later than December 15, 1997. Beginning no later than May 8, 2027, paragraphs (a)(1) and (b)(1) of this section no longer apply and each owner or operator shall meet the requirements in paragraphs (a)(2), (b)(2), and (c) of this section.

(2) For facilities that commenced construction after February 8, 1994, and on or before June 10, 2022, each owner or operator shall meet the requirements in paragraphs (a)(1), (b)(1), and (c) of this section upon startup. Beginning no later than May 8, 2027, paragraphs (a)(1) and (b)(1) of this section no longer apply and each owner or operator shall meet

the requirements in paragraphs (a)(2), (b)(2), and (c) of this section.

(3) For facilities that commenced construction after June 10, 2022, each owner or operator shall meet the requirements in paragraphs (a)(2), (b)(2), and (c) of this section upon startup or July 8, 2024, whichever is later.

(e) As an alternative to § 60.502(h) and (i) or § 60.502a(h) and (i) of this chapter as specified in paragraph (a) of this section, the owner or operator may comply with paragraphs (e)(1) and (2) of this section.

(1) The owner or operator shall design and operate the vapor processing system, vapor collection system, and liquid loading equipment to prevent gauge pressure in the railcar gasoline cargo tank from exceeding the applicable test limits in § 63.425(e) and (i) during product loading. This level is not to be exceeded when measured by the procedures specified in § 60.503(d) of this chapter during any performance test or performance evaluation conducted under § 63.425(b) or (c).

(2) No pressure-vacuum vent in the bulk' gasoline terminal's vapor processing system or vapor collection system may begin to open at a system pressure less than the applicable test limits in § 63.425(e) or (i).

■ 9. Revise § 63.423 to read as follows:

§ 63.423 Standards: Storage vessels.

(a) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall equip each gasoline storage vessel according to the requirements in paragraph (a)(1) or (2) of this section, as applicable in paragraph (c) of this section.

(1) Equip each gasoline storage vessel with a design capacity greater than or equal to 75 m³ according to the requirements in § 60.112b(a)(1) through (4) of this chapter, except for the requirements in § 60.112b(a)(1)(iv) through (ix) and (a)(2)(ii) of this chapter.

(2) Equip each gasoline external floating roof storage vessel with a design capacity greater than or equal to 75 m³ according to the requirements in § 60.112b(a)(2)(ii) of this chapter if such storage vessel does not currently meet the requirements in paragraph (a)(1) of this section.

(b) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall equip each gasoline storage vessel according to the requirements in paragraphs (b)(1) of this section and, if a floating roof is used, either paragraph (b)(2) or (3) of this section, as applicable in paragraph (c) of this section.

(1) Equip, maintain, and operate each gasoline storage vessel with a design capacity greater than or equal to 75 m³ according to the requirements in § 60.112b(a)(1) through (4) of this chapter, except for the requirements in § 60.112b(a)(1)(iv) through (ix) of this chapter. Alternatively, you may elect to equip, maintain, and operate each affected gasoline storage vessel with a design capacity greater than or equal to 75 m³ according to the requirements in subpart WW of this part as specified in § 60.110b(e)(5) of this chapter.

(2) Equip, maintain, and operate each internal floating control system to maintain the vapor concentration within the storage vessel above the floating roof at or below 25 percent of the lower explosive limit (LEL) on a 5-minute rolling average basis without the use of purge gas. This standard may require additional controls beyond those specified in paragraph (b)(1) of this section. Compliance with this paragraph (b)(2) shall be determined using the methods in § 63.425(j). A deviation of the LEL level is considered an inspection failure under § 60.113b(a)(2) of this chapter or § 63.1063(d)(2) and must be remedied as such. Any repairs made must be confirmed effective through re-monitoring of the LEL and meeting the level in this paragraph (b)(2) within the timeframes specified in § 60.113b(a)(2) or § 63.1063(e), as applicable.

(3) Equip, maintain, and operate each gasoline external floating roof storage vessel with a design capacity greater than or equal to 75 m³ with fitting controls as specified in § 60.112b(a)(2)(ii) of this chapter.

(c) Each gasoline storage vessel at bulk gasoline terminals and pipeline breakout stations shall be in compliance with the requirements of this section as expeditiously as practicable, but no later than the dates provided in paragraphs (c)(1) through (3) of this section.

(1) For facilities that commenced construction on or before February 8, 1994, each gasoline storage vessel shall meet the requirements in paragraph (a) of this section no later than December 15, 1997. Beginning no later than May 8, 2027, paragraph (a) of this section no longer applies and each gasoline storage vessel shall meet the requirements in paragraphs (b)(1) and (2) of this section no later than May 8, 2027. If applicable, the fitting controls required in paragraph (b)(3) of this section must be installed the next time the storage vessel is completely emptied and degassed, or by May 8, 2034, whichever occurs first.

(2) For facilities that commenced construction after February 8, 1994, and on or before June 10, 2022, each gasoline storage vessel shall meet the requirements in paragraph (a) of this section upon startup. Beginning no later than May 8, 2027, paragraph (a) of this section no longer applies and each gasoline storage vessel shall meet the requirements in paragraphs (b)(1) and (2) of this section no later than May 8, 2027. If applicable, the fitting controls required in paragraph (b)(3) of this section must be installed the next time the storage vessel is completely emptied and degassed, or by May 8, 2034, whichever occurs first.

(3) For facilities that commenced construction after June 10, 2022, each owner or operator shall meet the requirements in paragraph (b) of this section upon startup or July 8, 2024, whichever is later.

■ 10. Revise § 63.424 to read as follows:

§ 63.424 Standards: Equipment leaks.

(a) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall implement a leak detection and repair program for all equipment in gasoline service according to the requirements in paragraph (b) or (c) of this section, as applicable in paragraph (e) of this section and minimize gasoline vapor losses according to paragraph (d) of this section.

(b) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall perform a monthly leak inspection of all equipment in gasoline service. For this inspection, detection methods incorporating sight, sound, and smell are acceptable. Each piece of equipment shall be inspected during the loading of a gasoline cargo tank.

(1) A logbook shall be used and shall be signed by the owner or operator at the completion of each inspection. A section of the log shall contain a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility.

(2) Each detection of a liquid or vapor leak shall be recorded in the logbook. When a leak is detected, an initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in paragraph (b)(3) of this section.

(3) Delay of repair of leaking equipment will be allowed upon a demonstration to the Administrator that repair within 15 days is not feasible. The owner or operator shall provide the reason(s) a delay is needed and the date

by which each repair is expected to be completed.

(4) As an alternative to compliance with the provisions in paragraphs (b)(1) through (3) of this section, owners or operators may implement an instrument leak monitoring program that has been demonstrated to the Administrator as at least equivalent.

(c) Comply with the requirements in § 60.502a(j) of this chapter except as provided in paragraphs (c)(1) through (3) of this section.

(1) The frequency for optical gas imaging (OGI) monitoring shall be semiannually rather than quarterly as specified in § 60.502a(j)(1)(i).

(2) The frequency for Method 21 monitoring of pumps and valves shall be semiannually rather than quarterly as specified in § 60.502a(j)(1)(ii)(A) and (B).

(3) The frequency of monitoring of pressure relief devices shall be semiannually and within 5 calendar days after each pressure release rather than quarterly and within 5 calendar days after each pressure release as specified in § 60.502a(j)(4)(i).

(d) Owners and operators shall not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

(1) Minimize gasoline spills;

(2) Clean up spills as expeditiously as practicable;

(3) Cover all open gasoline containers with a gasketed seal when not in use; and

(4) Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

(e) Compliance with the provisions of this section shall be achieved as expeditiously as practicable, but no later than the dates provided in paragraphs (e)(1) through (3) of this section.

(1) For facilities that commenced construction on or before February 8, 1994, meet the requirements in paragraphs (b) and (d) of this section no later than December 15, 1997. Beginning no later than May 8, 2027, paragraph (b) of this section no longer applies and facilities shall meet the requirements in paragraphs (c) and (d) of this section no later than May 8, 2027.

(2) For facilities that commenced construction after February 8, 1994, and on or before June 10, 2022, meet the requirements in paragraphs (b) and (d) of this section upon startup. Beginning no later than May 8, 2027, paragraph (b) of this section no longer applies and facilities shall meet the requirements in paragraphs (c) and (d) of this section no later than May 8, 2027.

(3) For facilities that commenced construction after June 10, 2022, meet the requirements in paragraph (c) and (d) of this section upon startup or July 8, 2024, whichever is later.

■ 11. Section 63.425 is amended by:

■ a. Revising paragraphs (a) through (d), (e)(1), (f) introductory text, and (f)(1);

■ b. Revising equation term ''N'' in the equation in paragraph (g)(3);

■ c. Revising paragraph (h); and

■ d. Adding paragraph (j).

The revisions and addition read as follows:

§ 63.425 Test methods and procedures.

(a) *Performance test and evaluation requirements.* Each owner or operator subject to the emission standard in § 63.422(b)(1) or § 60.112b(a)(3)(ii) of this chapter shall comply with the requirements in paragraph (b) of this section. Each owner or operator subject to the emission standard in § 63.422(b)(2) shall comply with the requirements in paragraph (c) of this section. Performance tests shall be conducted under representative conditions when liquid product is being loaded into gasoline cargo tanks and shall include periods between gasoline cargo tank loading (when one cargo tank is disconnected and another cargo tank is moved into position for loading) provided that liquid product loading into gasoline cargo tanks is conducted for at least a portion of each 5 minute block of the performance test. 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 such conditions represent normal operation. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(b) *Gasoline loading rack and gasoline storage vessel performance test requirements.* For gasoline loading racks subject to the requirements in § 63.422(b)(1) or gasoline storage vessels subject to the requirements in § 60.112b(a)(3)(ii) of this chapter:

(1) Conduct a performance test on the vapor processing and collection systems according to either paragraph (b)(1)(i) or (ii) of this section.

(i) Use the test methods and procedures in § 60.503 of this chapter, except a reading of 500 ppm shall be used to determine the level of leaks to be repaired under § 60.503(b) of this chapter, or

(ii) Use alternative test methods and procedures in accordance with the alternative test method requirements in § 63.7(f).

(2) The performance test requirements of § 60.503(c) of this chapter do not apply to flares defined in § 63.421 and meeting the flare requirements in § 63.11(b). The owner or operator shall demonstrate that the flare and associated vapor collection system is in compliance with the requirements in § 63.11(b) and § 60.503(a), (b), and (d) of this chapter, respectively.

(3) For each performance test conducted under paragraph (b)(1) of this section, the owner or operator shall determine a monitored operating parameter value for the vapor processing system using the following procedure:

(i) During the performance test, continuously record the operating parameter under § 63.427(a);

(ii) Determine an operating parameter value based on the parameter data monitored during the performance test, supplemented by engineering assessments and the manufacturer's recommendations; and

(iii) Provide for the Administrator's approval the rationale for the selected operating parameter value, and monitoring frequency and averaging time, including data and calculations used to develop the value and a description of why the value, monitoring frequency, and averaging time demonstrate continuous compliance with the emission standard in § 63.422(b)(1) or § 60.112b(a)(3)(ii) of this chapter.

(4) For performance tests performed after the initial test, the owner or operator shall document the reasons for any change in the operating parameter value since the previous performance test.

(c) *Gasoline loading rack performance test and evaluation requirements.* For gasoline loading rack sources subject to the requirements in § 63.422(b)(2):

(1) Conduct performance tests or evaluations on the vapor processing and collection systems according to the requirements in § 60.503a(a), (c) and (d) of this chapter.

(2) The first performance test or performance evaluation of the continuous emissions monitoring system (CEMS) shall be conducted within 180 days of the date affected source begins compliance with the requirements in § 63.422(b)(2). A previously conducted performance test may be used to satisfy this requirement if the conditions in paragraphs (c)(2)(i)

through (v) of this section are met. Prior to conducting this performance test or evaluation, you must continue to meet the monitoring and operating limits that apply based on the previously conducted performance test.

(i) The performance test was conducted on or after May 8, 2022.

(ii) No changes have been made to the process or control device since the time of the performance test.

(iii) The operating conditions, test methods, and test requirements (*e.g.,* length of test) used for the previous performance test conform to the requirements in paragraph (c)(1) of this section.

(iv) The temperature in the combustion zone was recorded during the performance test as specified in § 60.503a(c)(8)(i) of this chapter and can be used to establish the operating limit as specified in § 60.503a(c)(8)(ii) through (iv) of this chapter.

(v) The performance test demonstrates compliance with the emission limit specified in § 63.422(b)(2).

(3) For loading racks complying with the mass loading emission limit in § 60.502a(c)(1) of this chapter, subsequent performance tests shall be conducted no later than 60 calendar months after the previous performance test.

(4) For loading racks complying with the concentration emission limit in § 60.502a(c)(2) of this chapter, subsequent performance evaluations of CEMS for the vapor collection and processing system shall be conducted no later than 12 calendar months after the previous performance evaluation.

(d) *Gasoline storage vessel requirements.* The owner or operator of each gasoline storage vessel subject to the provisions of § 63.423 shall comply with § 60.113b of this chapter and, if applicable, the provisions in paragraph (j) of this section. If a closed vent system and control device are used, as specified in § 60.112b(a)(3) of this chapter, to comply with the requirements in § 63.423, the owner or operator shall also comply with the requirements in paragraph (d)(1) or (2) of this section, as applicable.

(1) If the gasoline storage vessel is subject to the provision in § 63.423(a) or the provision in § 63.423(b) and a control device other than a flare is used for the gasoline storage vessel, the owner or operator shall also comply with the requirements in paragraph (b) of this section.

(2) If the gasoline storage vessel is subject to the provision in § 63.423(b) and a flare is used as the control device for the gasoline storage vessel, you must comply with the requirements in § 60.502a(c)(3) of this chapter as indicated in paragraphs (d)(2)(i) and (ii) of this section rather than the requirements in § 60.18(e) and (f) of this chapter as specified in § 60.113b(d) of this chapter.

(i) At § 60.502a(c)(3)(i) of this chapter, replace ''vapors displaced from gasoline cargo tanks during product loading'' with ''vapors from the gasoline storage vessel.''

(ii) Section 60.502a(c)(3)(vi) through (ix) of this chapter does not apply.

(e) * * *

(1) *Method 27 of appendix A–8 to part 60 of this chapter.* Conduct the test using a time period (t) for the pressure and vacuum tests of 5 minutes. The initial pressure (P_i) for the pressure test shall be 460 millimeters (mm) of water (H_2O) (18 inches (in.) H_2O), gauge. The initial vacuum (V_i) for the vacuum test shall be 150 mm H_2O (6 in. H_2O), gauge. Each owner or operator shall implement the requirements in paragraph (e)(1)(i) or (ii) of this section, as applicable in paragraph (e)(1)(iii) of this section.

(i) The maximum allowable pressure and vacuum changes (Δ p, Δ v) are as shown in the second column of table 1 to this paragraph (e)(1).

(ii) The maximum allowable pressure and vacuum changes (Δ p, Δ v) are as shown in the third column of table 1 to this paragraph (e)(1).

(iii) Compliance with the provisions of this section shall be achieved as expeditiously as practicable, but no later than the dates provided in paragraphs (e)(1)(iii)(A) and (B) of this section.

(A) For facilities that commenced construction on or before June 10, 2022, meet the requirements in paragraph (e)(1)(i) of this section prior to May 8, 2027, and meet the requirements in paragraph (e)(1)(ii) of this section no later than May 8, 2027.

(B) For facilities that commenced construction after June 10, 2022, meet the requirements in paragraph (e)(1)(ii) of this section upon startup or July 8, 2024, whichever is later.

TABLE 1 TO PARAGRAPH (e)(1)—ALLOWABLE CARGO TANK TEST PRESSURE OR VACUUM CHANGE

Cargo tank or compartment capacity, liters (gal)	Annual certification-allowable pressure or vacuum change (Δ p, Δ v) in 5 minutes, mm H_2O (in. H_2O)	Annual certification-allowable pressure or vacuum change (Δ p, Δ v) in 5 minutes, mm H_2O (in. H_2O)]	Allowable pressure change (Δ p) in 5 minutes at any time, mm H_2O (in. H_2O)
9,464 or more (2,500 or more)	25 (1.0)	12.7 (0.50)	64 (2.5)
9,463 to 5,678 (2,499 to 1,500)	38 (1.5)	19.1 (0.75)	76 (3.0)
5,677 to 3,785 (1,499 to 1,000)	51 (2.0)	25.4 (1.00)	89 (3.5)
3,784 or less (999 or less)	64 (2.5)	31.8 (1.25)	102 (4.0)

* * * * *

(f) *Leak detection test.* The leak detection test shall be performed using Method 21 of appendix A–7 to part 60 of this chapter. A vapor-tight gasoline cargo tank shall have no leaks at any time when tested according to the procedures in this paragraph (f).

(1) The instrument reading that defines a leak is 10,000 ppm (as propane). Use propane to calibrate the instrument, setting the span at the leak definition. The response time to 90 percent of the final stable reading shall be less than 8 seconds for the detector with the sampling line and probe attached.

* * * * *

(g) * * *

(3) * * *

N = 5-minute continuous performance standard at any time from the fourth column of table 1 to paragraph (e)(1) of this section, inches H_2O.

* * * * *

(h) *Continuous performance pressure decay test.* The continuous performance pressure decay test shall be performed using Method 27 in appendix A to part 60 of this chapter. Conduct only the positive pressure test using a time period (t) of 5 minutes. The initial pressure (P_i) shall be 460 mm H_2O (18 in. H_2O), gauge. The maximum allowable 5-minute pressure change (Δ p) which shall be met at any time is shown in the fourth column of table 1 to paragraph (e)(1) of this section.

* * * * *

(j) *LEL monitoring procedures.* Compliance with the vapor concentration below the LEL level for internal floating roof storage vessels at § 63.423(b)(2) shall be determined based on the procedures specified in paragraphs (j)(1) through (5) of this section. If tubing is necessary to obtain the measurements, the tubing must be non-crimping and made of Teflon or other inert material.

(1) LEL monitoring must be conducted at least once every 12 months and at other times upon request by the Administrator. If the measurement cannot be performed due to wind speeds exceeding those specified in paragraph (j)(3)(iii) of this section, the measurement must be performed within 30 days of the previous attempt.

(2) The calibration of the LEL meter must be checked per manufacturer specifications immediately before and after the measurements as specified in paragraphs (j)(2)(i) and (ii) of this section. If tubing will be used for the measurements, the tubing must be attached during calibration so that the calibration gas travels through the entire measurement system.

(i) Conduct the span check using a calibration gas recommended by the LEL meter manufacturer. The calibration gas must contain a single hydrocarbon at a concentration corresponding to 50 percent of the LEL (*e.g.,* 2.50 percent by volume when using methane as the calibration gas). The vendor must provide a Certificate of Analysis for the gas, and the certified concentration must be within ±2 percent (*e.g.,* 2.45 percent—2.55 percent by volume when using methane as the calibration gas). The LEL span response must be between 49 percent and 51 percent. If the span check prior to the measurements does not meet this requirement, the LEL meter must be recalibrated or replaced. If the span check after the measurements does not meet this requirement, the LEL meter must be recalibrated or replaced, and the measurements must be repeated.

(ii) Check the instrumental offset response using a certified compressed gas cylinder of zero air or an ambient environment that is free of organic compounds. The pre-measurement instrumental offset response must be 0 percent LEL. If the LEL meter does not meet this requirement, the LEL meter must be recalibrated or replaced.

(3) Conduct the measurements as specified in paragraphs (j)(3)(i) through (iv) of this section.

(i) Measurements of the vapors within the internal floating roof storage vessel must be collected no more than 3 feet above the internal floating roof.

(ii) Measurements shall be taken for a minimum of 20 minutes, logging the measurements at least once every 15 seconds, or until one 5-minute average as determined according to paragraph (j)(5)(ii) of this section exceeds the level specified in § 63.423(b)(2).

(iii) Measurements shall be taken when the wind speed at the top of the tank is 5 mph or less to the extent practicable, but in no case shall measurements be taken when the sustained wind speed at top of tank is greater than the annual average wind speed at the site or 15 mph, whichever is less.

(iv) Measurements should be conducted when the internal floating roof is floating with limited product movement (limited filling or emptying of the tank).

(4) To determine the actual vapor concentration within the storage vessel, the percent of the LEL ''as the calibration gas'' must be corrected according to one of the following procedures. Alternatively, if the LEL meter used has correction factors that can be selected from the meter's program, you may enable this feature to automatically apply one of the correction factors specified in paragraphs (j)(4)(i) and (ii) of this section.

(i) Multiply the measurement by the published gasoline vapor correction factor for the specific LEL meter and calibration gas used.

(ii) If there is no published correction factor for gasoline vapors for the specific LEL meter used, multiply the measurement by the published correction factor for butane as a surrogate for determining the LEL of gasoline vapors. The correction factor must correspond to the calibration gas used.

(5) Use the calculation procedures in paragraphs (j)(5)(i) through (iii) of this section to determine compliance with the LEL level.

(i) For each minute while measurements are being taken, determine the one-minute average reading as the arithmetic average of the corrected individual measurements (taken at least once every 15 seconds) during the minute.

(ii) Starting with the end of the fifth minute of data, calculate a five-minute rolling average as the arithmetic average of the previous five one-minute readings determined under paragraph (j)(5)(i) of this section. Determine a new five-minute average reading for every subsequent one-minute reading.

(iii) Each five-minute rolling average must meet the LEL level specified in § 63.423(b)(2).

■ 12. Section 63.427 is amended by revising paragraphs (a) introductory text, (a)(3), (b), and (c) and adding paragraphs (d), (e), and (f) to read as follows:

§ 63.427 Continuous monitoring.

(a) Each owner or operator of a bulk gasoline terminal subject to the provisions in § 63.422(b)(1) shall install, calibrate, certify, operate, and maintain, according to the manufacturer's specifications, a continuous monitoring system (CMS) as specified in paragraph (a)(1), (2), (3), or (4) of this section, except as allowed in paragraph (a)(5) of this section.

* * * * *

(3) Where a thermal oxidation system is used, a CPMS capable of measuring temperature must be installed in the firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs.

* * * * *

(b) Each owner or operator of a bulk gasoline terminal subject to the provisions in § 63.422(b)(1) shall operate the vapor processing system in a manner not to exceed the operating parameter value for the parameter described in paragraphs (a)(1) and (2) of this section, or to go below the operating parameter value for the parameter described in paragraph (a)(3) of this section, and established using the procedures in § 63.425(b). In cases where an alternative parameter pursuant to paragraph (a)(5) of this section is approved, each owner or operator shall operate the vapor processing system in a manner not to exceed or not to go below, as appropriate, the alternative operating parameter value. Operation of the vapor processing system in a manner exceeding or going below the operating parameter value, as specified above, shall constitute a violation of the emission standard in § 63.422(b)(1).

(c) Except as provided in paragraph (f) of this section, each owner or operator of a bulk gasoline terminal subject to the provisions in § 63.422(b)(2) shall install, calibrate, certify, operate, and maintain a CMS as specified in § 60.504a(a) through (d) of this chapter, as applicable. You may use the limited alternative monitoring methods as specified in § 60.504a(e) of this chapter, if applicable.

(d) Each owner or operator of a bulk gasoline terminal subject to the provisions in § 63.422(b)(2) shall operate the vapor processing system in a manner consistent with the minimum and/or maximum operating parameter value or procedures described in §§ 60.502a(a) and (c) and 60.504a(a) and (c) of this chapter. Operation of the vapor processing system in a manner that constitutes a period of excess emissions or failure to perform procedures required shall constitute a deviation of the emission standard in § 63.422(b)(2).

(e) Each owner or operator of gasoline storage vessels subject to the provisions of § 63.423 shall comply with the monitoring requirements in § 60.116b of this chapter, except records shall be kept for at least 5 years. If a closed vent system and control device are used, as specified in § 60.112b(a)(3) of this chapter, to comply with the requirements in § 63.423, the owner or operator shall also comply with the requirements in paragraph (e)(1) or (2) of this section, as applicable.

(1) If the gasoline storage vessel is subject to the provision in § 63.423(a) or if the gasoline storage vessel is subject to the provision in § 63.423(b) and a control device other than a flare is used for the gasoline storage vessel, the owner or operator shall also comply with the requirements in paragraph (a) of this section.

(2) If the gasoline storage vessel is subject to the provision in § 63.423(b) and a flare is used as the control device for the affected gasoline storage vessel, you must comply with the monitoring requirements in § 60.504a(c) of this chapter.

(f) As an alternative to the pressure monitoring requirements in § 60.504a(d) of this chapter, you may comply with the pressure monitoring requirements in § 60.503(d) of this chapter during any performance test or performance evaluation conducted under § 63.425(c) to demonstrate compliance with the provisions in § 60.502a(h) of this chapter.

■ 13. Revising § 63.428 to read as follows:

§ 63.428 Recordkeeping and reporting.

(a) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by December 16, 1996, whichever is later. Affected sources that are major sources on December 16, 1996, and plan to be area sources by December 15, 1997, shall include in this notification a brief, non-binding description of and schedule for the action(s) that are planned to achieve area source status.

(b) Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall keep records in either hardcopy or electronic form of the test results for each gasoline cargo tank loading at the facility for at least 5 years as specified in paragraphs (b)(1) through (3) of this section. Each owner or operator of a bulk gasoline terminal subject to the provisions of this subpart shall keep records for at least 5 years as specified in paragraphs (b)(4) and (5) of this section.

(1) Annual certification testing performed under § 63.425(e) and railcar bubble leak testing performed under § 63.425(i); and

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

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

(i) Name of test: Annual Certification Test—Method 27 (§ 63.425(e)(1)); Annual Certification Test—Internal Vapor Valve (§ 63.425(e)(2)); Leak Detection Test (§ 63.425(f)); Nitrogen Pressure Decay Field Test (§ 63.425(g)); Continuous Performance Pressure Decay Test (§ 63.425(h)); or Railcar Bubble Leak Test Procedure (§ 63.425(i)).

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

(iii) Cargo tank identification number.

(iv) Test location and date.

(v) Tester name and signature.

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

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

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

(4) Records of each instance in which liquid product was loaded into a gasoline cargo tank for which vapor tightness documentation required under § 60.502(e)(1) or § 60.502a(e)(1) of this chapter, as applicable, was not provided or available in the terminal's records. These records shall include, at a minimum:

(i) Cargo tank owner and address.

(ii) Cargo tank identification number.

(iii) Date and time liquid product was loaded into a gasoline cargo tank without proper documentation.

(iv) Date proper documentation was received or statement that proper documentation was never received.

(5) Records of each instance when liquid product was loaded into gasoline cargo tanks not using submerged filling, as defined in § 63.421, not equipped with vapor collection equipment that is compatible with the terminal's vapor collection system, or not properly connected to the terminal's vapor collection system. These records shall include, at a minimum:

(i) Date and time of liquid product loading into gasoline cargo tank not using submerged filling, improperly equipped or improperly connected.

(ii) Type of deviation (*e.g.,* not submerged filling, incompatible equipment, not properly connected).

(iii) Cargo tank identification number.

(c) Each owner or operator of a bulk gasoline terminal subject to the provisions in § 63.422(b)(1) shall:

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

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

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

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

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

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

(3) If an owner or operator requests approval to use a vapor processing system or monitor an operating parameter other than those specified in § 63.427(a), the owner or operator shall submit a description of planned reporting and recordkeeping procedures. The Administrator will specify appropriate reporting and recordkeeping requirements as part of the review of the permit application.

(4) Keep written procedures required under § 63.8(d)(2) on record 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 shall 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 shall be included in the plan as required under § 63.8(d)(2).

(d) Each owner or operator of a bulk gasoline terminal subject to the provisions in § 63.422(b)(2) shall keep records as specified in paragraphs (d)(1) through (4) of this section, as applicable, for a minimum of five years unless otherwise specified in this section:

(1) For each thermal oxidation system used to comply with the emission limitations in § 63.422(b)(2) by monitoring the combustion zone temperature as specified in § 60.502a(c)(1)(ii) of this chapter, for each pressure CPMS used to comply with the requirements in § 60.502a(h) of this chapter, and for each vapor recovery system used to comply with the emission limitations in § 63.422(b)(2), maintain records, as applicable, of:

(i) The applicable operating or emission limit for the CMS. For combustion zone temperature operating limits, include the applicable date range the limit applies based on when the performance test was conducted.

(ii) Each 3-hour rolling average combustion zone temperature measured by the temperature CPMS, each 5-minute average reading from the pressure CPMS, and each 3-hour rolling average total organic compounds (TOC) concentration (as propane) measured by the TOC CEMS.

(iii) For each deviation of the 3-hour rolling average combustion zone temperature operating limit, maximum loading pressure specified in § 60.502a(h) of this chapter, or 3-hour rolling average TOC concentration (as propane), the start date and time, duration, cause, and the corrective action taken.

(iv) For each period when there was a CMS outage or the CMS was out of control, the start date and time, duration, cause, and the corrective action taken. For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter is used, the corrective action taken shall include an indication of the use of the limited alternative for vapor recovery systems in § 60.504a(e).

(v) Each inspection or calibration of the CMS including a unique identifier, make, and model number of the CMS, and date of calibration check. For TOC CEMS, include the type of CEMS used (*i.e.,* flame ionization detector, nondispersive infrared analyzer) and an indication of whether methane is excluded from the TOC concentration reported in paragraph (d)(1)(ii) of this section.

(vi) TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter is used, also keep records of:

(A) The quantity of liquid product loaded in gasoline cargo tanks for the past 10 adsorption cycles prior to the CEMS outage.

(B) The vacuum pressure, purge gas quantities, and duration of the vacuum/purge cycles used for the past 10 desorption cycles prior to the CEMS outage.

(C) The quantity of liquid product loaded in gasoline cargo tanks for each adsorption cycle while using the alternative.

(D) The vacuum pressure, purge gas quantities, and duration of the vacuum/purge cycles for each desorption cycle while using the alternative.

(2) For each flare used to comply with the emission limitations in § 63.422(b)(2) and for each thermal oxidation system using the flare monitoring alternative as provided in § 60.502a(c)(1)(iii) of this chapter, maintain records of:

(i) 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 gasoline vapors were routed to the flare for a minimum of 5 years. The record must identify the start and end time and date of each 15-minute block.

(ii) Visible emissions observations as specified in paragraphs (d)(2)(ii)(A) and (B) of this section, as applicable, for a minimum of 3 years.

(A) If visible emissions observations are performed using Method 22 of appendix A–7 to part 60 of this chapter, the record must identify the date, the start and end time of the visible emissions observation, and the number of minutes for which visible emissions were observed during the observation. If the owner or operator performs visible emissions observations more than one time during a day, include separate records for each visible emissions observation performed.

(B) For each 2-hour period for which visible emissions are observed for more than 5 minutes in 2 consecutive hours but visible emissions observations according to Method 22 of appendix A–7 to part 60 of this chapter were not conducted for the full 2-hour period, the record must include the date, the start and end time of the visible emissions observation, and an estimate of the cumulative number of minutes in the 2-hour period for which emissions were visible based on best information available to the owner or operator.

(iii) Each 15-minute block period during which operating values are outside of the applicable operating limits specified in § 63.670(d) through (f) when liquid product is being loaded into gasoline cargo tanks for at least 15-minutes identifying the specific operating limit that was not met.

(iv) The 15-minute block average cumulative flows for the thermal oxidation system vent gas or 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 start and end time 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 thermal oxidation system vent gas, 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. If you use the supplemental gas flow rate monitoring alternative in § 60.502a(c)(3)(viii) of this chapter, the required supplemental gas flow rate (winter and summer, if applicable) and the actual monitored supplemental gas flow rate for the 15-minute block. Retain the supplemental gas flow rate records for a minimum of 5 years.

(v) The thermal oxidation system vent gas or 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 NHV_{vg} analyzer is used, retain records of the 15-minute block average values for a minimum of 5 years. If you demonstrate your gas streams have consistent composition using the provisions in § 63.670(j)(6) as specified in § 60.502a(c)(3)(vii) of this chapter, retain records of the required minimum ratio of gasoline loaded to total liquid product loaded and the actual ratio on a 15-minute block basis.

If applicable, you must retain records of the required minimum gasoline loading rate as specified in § 60.502a(c)(3)(vii) and the actual gasoline loading rate on a 15-minute block basis for a minimum of 5 years.

(vi) Each 15-minute block average operating parameter calculated following the methods specified in § 63.670(k) through (n), as applicable.

(vii) All periods during which the owner or operator does not perform monitoring according to the procedures in § 63.670(g), (i), and (j) or in § 60.502a(c)(3)(vii) and (viii) of this chapter as applicable. Note the start date, start time, and duration in minutes for each period.

(viii) An indication of whether ''vapors displaced from gasoline cargo tanks during product loading'' excludes periods when liquid product is loaded but no gasoline cargo tanks are being loaded or if liquid product loading is assumed to be loaded into gasoline cargo tanks according to the provisions in § 60.502a(c)(3)(i) of this chapter, records of all time periods when ''vapors displaced from gasoline cargo tanks during product loading'', and records of time periods when there were no ''vapors displaced from gasoline cargo tanks during product loading''.

(ix) If you comply with the flare tip velocity operating limit using the one-time flare tip velocity operating limit compliance assessment as provided in § 60.502a(c)(3)(ix) of this chapter, maintain records of the applicable one-time flare tip velocity operating limit compliance assessment for as long as you use this compliance method.

(x) For each parameter monitored using a CMS, retain the records specified in paragraphs (d)(2)(x)(A) through (C) of this section, as applicable:

(A) For each deviation, record the start date and time, duration, cause, and corrective action taken.

(B) For each period when there is a CMS outage or the CMS is out of control, record the start date and time, duration, cause, and corrective action taken.

(C) Each inspection or calibration of the CMS including a unique identifier, make, and model number of the CMS, and date of calibration check.

(3) Records of all 5-minute time periods during which liquid product is loaded into gasoline cargo tanks or assumed to be loaded into gasoline cargo tanks and records of all 5-minute time periods when there was no liquid product loaded into gasoline cargo tanks.

(4) Keep written procedures required under § 63.8(d)(2) on record 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 shall 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 shall be included in the plan as required under § 63.8(d)(2).

(e) Each owner or operator of storage vessels subject to the provisions of this subpart shall keep records as specified in § 60.115b of this chapter, except records shall be kept for at least 5 years. Additionally, for each storage vessel complying with the provisions in § 63.423(b)(2), keep records of each LEL monitoring event as specified in paragraphs (e)(1) through (9) of this section.

(1) Date and time of the LEL monitoring, and the storage vessel being monitored.

(2) A description of the monitoring event (*e.g.,* monitoring conducted concurrent with visual inspection required under § 60.113b(a)(2) of this chapter or § 63.1063(d)(2); monitoring that occurred on a date other than the visual inspection required under § 60.113b(a)(2) or § 63.1063(d)(2); re-monitoring due to high winds; re-monitoring after repair attempt).

(3) Wind speed at the top of the storage vessel on the date of LEL monitoring.

(4) The LEL meter manufacturer and model number used, as well as an indication of whether tubing was used during the LEL monitoring, and if so, the type and length of tubing used.

(5) Calibration checks conducted before and after making the measurements, including both the span check and instrumental offset. This includes the hydrocarbon used as the calibration gas, the Certificate of Analysis for the calibration gas(es), the results of the calibration check, and any corrective action for calibration checks that do not meet the required response.

(6) Location of the measurements and the location of the floating roof.

(7) Each measurement (taken at least once every 15 seconds). The records should indicate whether the recorded values were automatically corrected using the meter's programming. If the values were not automatically corrected, record both the raw (as the calibration gas) and corrected measurements, as well as the correction factor used.

(8) Each 5-minute rolling average reading.

(9) If the vapor concentration of the storage vessel was above 25 percent of the LEL on a 5-minue rolling average basis, a description of whether the floating roof was repaired, replaced, or taken out of gasoline service.

(f) Each owner or operator complying with the provisions of § 63.424 shall keep records of the information in paragraphs (f)(1) and (2) of this section.

(1) Each owner or operator complying with the provisions of § 63.424(b) shall record the following information in the logbook for each leak that is detected:

(i) The equipment type and identification number;

(ii) The nature of the leak (*i.e.,* vapor or liquid) and the method of detection (*i.e.,* sight, sound, or smell);

(iii) The date the leak was detected and the date of each attempt to repair the leak;

(iv) Repair methods applied in each attempt to repair the leak;

(v) ''Repair delayed'' and the reason for the delay if the leak is not repaired within 15 calendar days after discovery of the leak;

(vi) The expected date of successful repair of the leak if the leak is not repaired within 15 days; and

(vii) The date of successful repair of the leak.

(2) Each owner or operator complying with the provisions of § 63.424(c) or § 60.503a(a)(2) of this chapter shall keep records of the following information:

(i) Types, identification numbers, and locations of all equipment in gasoline service.

(ii) For each leak inspection conducted under § 63.424(c) or § 60.503a(a)(2) of this chapter, keep the following records:

(A) An indication if the leak inspection was conducted under § 63.424(c) or § 60.503a(a)(2) of this chapter.

(B) Leak determination method used for the leak inspection.

(iii) For leak inspections conducted with Method 21 of appendix A–7 to part 60 of this chapter, keep the following additional records:

(A) Date of inspection.

(B) Inspector name.

(C) Monitoring instrument identification.

(D) Identification of all equipment surveyed and the instrument reading for each piece of equipment.

(E) Date and time of instrument calibration and initials of operator performing the calibration.

(F) Calibration gas cylinder identification, certification date, and certified concentration.

(G) Instrument scale used.

(H) Results of the daily calibration drift assessment.

(iv) For leak inspections conducted with OGI, keep the records specified in section 12 of appendix K to part 60 of this chapter.

(v) For each leak that is detected during a leak inspection or by audio/visual/olfactory methods during normal duties, record the following information:

(A) The equipment type and identification number.

(B) The date the leak was detected, the name of the person who found the leak, nature of the leak (*i.e.,* vapor or liquid) and the method of detection (*i.e.,* audio/visual/olfactory, Method 21 of appendix A–7 to part 60 of this chapter, or OGI).

(C) The date of each attempt to repair the leak and the repair methods applied in each attempt to repair the leak.

(D) The date of successful repair of the leak, the method of monitoring used to confirm the repair, and if Method 21 of appendix A–7 to part 60 of this chapter is used to confirm the repair, the maximum instrument reading measured by Method 21 of appendix A–7 to part 60. If OGI is used to confirm the repair, keep video footage of the repair confirmation.

(E) For each repair delayed beyond 15 calendar days after discovery of the leak, record ‘‘Repair delayed’’, the reason for the delay, and the expected date of successful repair. The owner or operator (or designate) whose decision it was that repair could not be carried out in the 15-calendar day timeframe must sign the record.

(F) For each leak that is not repairable, the maximum instrument reading measured by Method 21 of appendix A–7 to part 60 of this chapter at the time the leak is determined to be not repairable, a video captured by the OGI camera showing that emissions are still visible, or a signed record that the leak is still detectable via audio/visual/olfactory methods.

(g) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall keep the following records for each deviation of an emissions limitation (including operating limit), work practice standard, or operation and maintenance requirement in this subpart.

(1) Date, start time, and duration of each deviation.

(2) List of the affected sources or equipment for each deviation, an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions.

(3) Actions taken to minimize emissions.

(h) Any records required to be maintained by this subpart that are submitted electronically via the U.S. Environmental Protection Agency (EPA) Compliance and Emissions Data Reporting Interface (CEDRI) may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated authority or the EPA as part of an on-site compliance evaluation.

(i) Records of each performance test or performance evaluation conducted and each notification and report submitted to the Administrator for at least 5 years. For each performance test, include an indication of whether liquid product loading is assumed to be loaded into gasoline cargo tanks or periods when liquid product is loaded but no gasoline cargo tanks are being loaded are excluded in the determination of the combustion zone temperature operating limit according to the provision in § 60.503a(c)(8)(ii) of this chapter. If complying with the alternative in § 63.427(f), for each performance test or performance evaluation conducted, include the pressure every 5 minutes while a gasoline cargo tank is being loaded and the highest instantaneous pressure that occurs during each loading.

(j) Prior to November 4, 2024, each owner or operator of an affected source under this subpart shall submit performance test reports to the Administrator according to the requirements in § 63.13. Beginning on November 4, 2024, within 60 days after the date of completing each performance test and each CEMS performance evaluation required by this subpart, you must submit the results of the performance test following the procedure specified in § 63.9(k). As required by § 63.7(g)(2)(iv), you must include the value for the combustion zone temperature operating parameter limit set based on your performance test in the performance test report. If the monitoring alternative in § 63.427(f) is used, indicate that this monitoring alternative is being used, identify each loading rack that loads gasoline cargo tanks at the bulk gasoline terminal subject to the provisions of this subpart, and report the highest instantaneous pressure monitored during the performance test or performance evaluation for each identified loading rack. Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) and performance evaluations of CEMS measuring RATA pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test or performance evaluation must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT and performance evaluations of CEMS measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

(k) The owner or operator must submit all Notification of Compliance Status reports in PDF format to the EPA following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Gasoline Distribution Sector Lead.

(l) Prior to May 8, 2027, each owner or operator of a source subject to the requirements of this subpart shall submit reports as specified in paragraphs (l)(1) through (5) of this section, as applicable.

(1) Each owner or operator subject to the provisions of § 63.424 shall report to the Administrator a description of the types, identification numbers, and locations of all equipment in gasoline service. For facilities electing to implement an instrument program under § 63.424(b)(4), the report shall contain a full description of the program.

(i) In the case of an existing source or a new source that has an initial startup date before December 14, 1994, the report shall be submitted with the notification of compliance status required under § 63.9(h), unless an extension of compliance is granted under § 63.6(i). If an extension of compliance is granted, the report shall be submitted on a date scheduled by the Administrator.

(ii) In the case of new sources that did not have an initial startup date before December 14, 1994, the report shall be submitted with the application for approval of construction, as described in § 63.5(d).

(2) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall include in a semiannual

report to the Administrator the following information, as applicable:

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

(ii) Periodic reports as specified in § 60.115b of this chapter; and

(iii) The number of equipment leaks not repaired within 5 days after detection.

(3) Each owner or operator of a bulk gasoline terminal or pipeline breakout station subject to the provisions of this subpart shall submit an excess emissions report to the Administrator in accordance with § 63.10(e)(3), whether or not a CMS is installed at the facility. The following occurrences are excess emissions events under this subpart, and the following information shall be included in the excess emissions report, as applicable:

(i) Each exceedance or failure to maintain, as appropriate, the monitored operating parameter value determined under § 63.425(b)(3). The report shall include the monitoring data for the days on which exceedances or failures to maintain have occurred, and a description and timing of the steps taken to repair or perform maintenance on the vapor collection and processing systems or the CMS.

(ii) Each instance of a nonvapor-tight gasoline cargo tank loading at the facility in which the owner or operator failed to take steps to assure that such cargo tank would not be reloaded at the facility before vapor tightness documentation for that cargo tank was obtained.

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

(iv) For each occurrence of an equipment leak for which no repair attempt was made within 5 days or for which repair was not completed within 15 days after detection:

(A) The date on which the leak was detected;

(B) The date of each attempt to repair the leak;

(C) The reasons for the delay of repair; and

(D) The date of successful repair.

(4) Each owner or operator of a facility meeting the criteria in § 63.420(c) shall perform the requirements of this paragraph (l)(4), all of which will be available for public inspection:

(i) Document and report to the Administrator not later than December 16, 1996, for existing facilities, within 30 days for existing facilities subject to § 63.420(c) after December 16, 1996, or at startup for new facilities the methods, procedures, and assumptions supporting the calculations for determining criteria in § 63.420(c);

(ii) Maintain records to document that the facility parameters established under § 63.420(c) have not been exceeded; and

(iii) Report annually to the Administrator that the facility parameters established under § 63.420(c) have not been exceeded.

(iv) At any time following the notification required under paragraph (l)(4)(i) of this section and approval by the Administrator of the facility parameters, and prior to any of the parameters being exceeded, the owner or operator may submit a report to request modification of any facility parameter to the Administrator for approval. Each such request shall document any expected HAP emission change resulting from the change in parameter.

(5) Each owner or operator of a facility meeting the criteria in § 63.420(d) shall perform the requirements of this paragraph (l)(5), all of which will be available for public inspection:

(i) Document and report to the Administrator not later than December 16, 1996, for existing facilities, within 30 days for existing facilities subject to § 63.420(d) after December 16, 1996, or at startup for new facilities the use of the emission screening equations in § 63.420(a)(1) or (b)(1) and the calculated value of E_T or E_P;

(ii) Maintain a record of the calculations in § 63.420 (a)(1) or (b)(1), including methods, procedures, and assumptions supporting the calculations for determining criteria in § 63.420(d); and

(iii) At any time following the notification required under paragraph (l)(5)(i) of this section, and prior to any of the parameters being exceeded, the owner or operator may notify the Administrator of modifications to the facility parameters. Each such notification shall document any expected HAP emission change resulting from the change in parameter.

(m) On or after May 8, 2027, you must submit to the Administrator semiannual reports with the applicable information in paragraphs (m)(1) through (8) of this section following the procedure specified in paragraph (n) of this section.

(1) Report the following general facility information:

(i) Facility name.

(ii) Facility physical address, including city, county, and State.

(iii) Latitude and longitude of facility's physical location. Coordinates must be in decimal degrees with at least five decimal places.

(iv) The following information for the contact person:

(A) Name.

(B) Mailing address.

(C) Telephone number.

(D) Email address.

(v) The type of facility (bulk gasoline terminal or pipeline breakout station).

(vi) Date of report and beginning and ending dates of the reporting period. You are no longer required to provide the date of report when the report is submitted via CEDRI.

(vii) 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. If your report is submitted via CEDRI, the certifier's electronic signature during the submission process replaces the requirement in this paragraph (m)(1)(vii).

(2) For each thermal oxidation system used to comply with the emission limit in § 60.502a(c)(1) of this chapter by monitoring the combustion zone temperature as specified in § 60.502a(c)(1)(ii), for each pressure CPMS used to comply with the requirements in § 60.502a(h), and for each vapor recovery system used to comply with the emission limitations in § 60.502a(c)(2), report the following information for the CMS:

(i) For all instances when the temperature CPMS measured 3-hour rolling averages below the established operating limit or when the vapor collection system pressure exceeded the maximum loading pressure specified in § 60.502a(h) of this chapter when liquid product was being loaded into gasoline cargo tanks or when the TOC CEMS measured 3-hour rolling average concentrations higher than the applicable emission limitation when the vapor recovery system was operating:

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) Each 3-hour rolling average combustion zone temperature, average pressure, or 3-hour rolling average TOC concentration during the deviation. For TOC concentration, indicate whether methane is excluded from the TOC concentration.

(D) A unique identifier for the CMS.

(E) The make, model number, and date of last calibration check of the CMS.

(F) The cause of the deviation and the corrective action taken.

(ii) For all instances that the temperature CPMS for measuring the combustion zone temperature or pressure CPMS was not operating or out of control when liquid product was loaded into gasoline cargo tanks, or the TOC CEMS was not operating or was out of control when the vapor recovery system was operating:

(A) The date and start time of the deviation.

(B) The duration of the deviation in hours.

(C) A unique identifier for the CMS.

(D) The make, model number, and date of last calibration check of the CMS.

(E) The cause of the deviation and the corrective action taken. For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter is used, the corrective action taken shall include an indication of the use of the limited alternative for vapor recovery systems in § 60.504a(e).

(F) For TOC CEMS outages where the limited alternative for vapor recovery systems in § 60.504a(e) of this chapter is used, report either an indication that there were no deviations from the operating limits when using the limited alternative or report the number of each of the following types of deviations that occurred during the use of the limited alternative for vapor recovery systems in § 60.504a(e).

(*1*) The number of adsorption cycles when the quantity of liquid product loaded in gasoline cargo tanks exceeded the operating limit established in § 60.504a(e)(1) of this chapter. Enter 0 if no deviations of this type.

(*2*) The number of desorption cycles when the vacuum pressure was below the average vacuum pressure as specified in § 60.504a(e)(2)(i) of this chapter. Enter 0 if no deviations of this type.

(*3*) The number of desorption cycles when the quantity of purge gas used was below the average quantity of purge gas as specified in § 60.504a(e)(2)(ii) of this chapter. Enter 0 if no deviations of this type.

(*4*) The number of desorption cycles when the duration of the vacuum/purge cycle was less than the average duration as specified in § 60.504a(e)(2)(iii) of this chapter. Enter 0 if no deviations of this type.

(3) For each flare used to comply with the emission limitations in § 60.502a(c)(3) of this chapter and for each thermal oxidation system using the flare monitoring alternative as provided in § 60.502a(c)(1)(iii), report:

(i) The date and start and end times for each of the following instances:

(A) Each 15-minute block during which there was at least one minute when gasoline vapors were routed to the flare and no pilot flame was present.

(B) Each period of 2 consecutive hours during which visible emissions exceeded a total of 5 minutes. Additionally, report the number of minutes for which visible emissions were observed during the observation or an estimate of the cumulative number of minutes in the 2-hour period for which emissions were visible based on best information available to the owner or operator.

(C) Each 15-minute period for which the applicable operating limits specified in § 63.670(d) through (f) were not met. You must identify the specific operating limit that was not met. Additionally, report the information in paragraphs (m)(3)(i)(C)(*1*) through (*3*) of this section, as applicable.

(*1*) If you use the loading rate operating limits as determined in § 60.502a(c)(3)(vii) of this chapter alone or in combination with the supplemental gas flow rate monitoring alternative in § 60.502a(c)(3)(viii) of this chapter, the required minimum ratio and the actual ratio of gasoline loaded to total product loaded for the rolling 15-minute period and, if applicable, the required minimum quantity and the actual quantity of gasoline loaded, in gallons, for the rolling 15-minute period.

(*2*) If you use the supplemental gas flow rate monitoring alternative in § 60.502a(c)(3)(viii) of this chapter, the required minimum supplemental gas flow rate and the actual supplemental gas flow rate including units of flow rates for the 15-minute block.

(*3*) If you use parameter monitoring systems other than those specified in paragraphs (m)(3)(i)(C)(*1*) and (*2*) of this section, the value of the net heating value operating parameter(s) during the deviation determined following the methods in § 63.670(k) through (n) as applicable.

(ii) The start date, start time, and duration in minutes for each period when "vapors displaced from gasoline cargo tanks during product loading" were routed to the flare or thermal oxidation system and the applicable monitoring was not performed.

(iii) For each instance reported under paragraphs (m)(3)(i) and (ii) of this section that involves CMS, report the following information:

(A) A unique identifier for the CMS.

(B) The make, model number, and date of last calibration check of the CMS.

(C) The cause of the deviation or downtime and the corrective action taken.

(4) For any instance in which liquid product was loaded into a gasoline cargo tank for which vapor tightness documentation required under § 60.502a(e)(1) of this chapter was not provided or available in the terminal's records, report:

(i) Cargo tank owner and address.

(ii) Cargo tank identification number.

(iii) Date and time liquid product was loaded into a gasoline cargo tank without proper documentation.

(iv) Date proper documentation was received or statement that proper documentation was never received.

(5) For each instance when liquid product was loaded into gasoline cargo tanks not using submerged filling, as defined in § 63.421, not equipped with vapor collection equipment that is compatible with the terminal's vapor collection system, or not properly connected to the terminal's vapor collection system, report:

(i) Date and time of liquid product loading into gasoline cargo tank not using submerged filling, improperly equipped, or improperly connected.

(ii) The type of deviation (*e.g.,* not submerged filling, incompatible equipment, not properly connected).

(iii) Cargo tank identification number.

(6) Report the following information for each leak inspection required and each leak identified under § 63.424(c) and § 60.503a(a)(2) of this chapter.

(i) For each leak detected during a leak inspection required under § 63.424(c) and § 60.503a(a)(2) of this chapter, report:

(A) The date of inspection.

(B) The leak determination method (OGI or Method 21).

(C) The total number and type of equipment for which leaks were detected.

(D) The total number and type of equipment for which leaks were repaired within 15 calendar days.

(E) The total number and type of equipment for which no repair attempt was made within 5 calendar days of the leaks being identified.

(F) The total number and types of equipment that were placed on the delay of repair, as specified in § 60.502a(j)(8) of this chapter.

(ii) For leaks identified under § 63.424(c) by audio/visual/olfactory methods during normal duties report:

(A) The total number and type of equipment for which leaks were identified.

(B) The total number and type of equipment for which leaks were repaired within 15 calendar days.

(C) The total number and type of equipment for which no repair attempt was made within 5 calendar days of the leaks being identified.

(D) The total number and type of equipment placed on the delay of repair, as specified in § 60.502a(j)(8) of this chapter.

(iii) The total number of leaks on the delay of repair list at the start of the reporting period.

(iv) The total number of leaks on the delay of repair list at the end of the reporting period.

(v) For each leak that was on the delay of repair list at any time during the reporting period, report:

(A) Unique equipment identification number.

(B) Type of equipment.

(C) Leak determination method (OGI, Method 21, or audio/visual/olfactory).

(D) The reason(s) why the repair was not feasible within 15 calendar days.

(E) If applicable, the date repair was completed.

(7) For each gasoline storage vessel subject to requirements in § 63.423, report:

(i) The information specified in § 60.115b(a) or (b) of this chapter or deviations in measured parameter values from the plan specified in § 60.115b(c) of this chapter, depending upon the control equipment installed, or, if applicable, the information specified in § 63.1066(b).

(ii) If you are complying with § 63.423(b)(2), for each deviation in LEL monitoring, report:

(A) Date and start and end times of the LEL monitoring, and the storage vessel being monitored.

(B) Description of the monitoring event, *e.g.,* monitoring conducted concurrent with visual inspection required under § 60.113b(a)(2) of this chapter or § 63.1063(d)(2); monitoring that occurred on a date other than the visual inspection required under § 60.113b(a)(2) or § 63.1063(d)(2); re-monitoring due to high winds; re-monitoring after repair attempt.

(C) Wind speed in miles per hour at the top of the storage vessel on the date of LEL monitoring.

(D) The highest 5-minute rolling average reading during the monitoring event.

(E) Whether the floating roof was repaired, replaced, or taken out of gasoline service. If the floating roof was repaired or replaced, also report the information in paragraphs (m)(7)(ii)(A) through (D) of this section for each re-monitoring conducted to confirm the repair.

(8) If there were no deviations from the emission limitations, operating parameters, or work practice standards, then provide a statement that there were no deviations from the emission limitations, operating parameters, or work practice standards during the reporting period. If there were no periods during which a continuous monitoring system (including a CEMS or CPMS) was inoperable or out-of-control, then provide a statement that there were no periods during which a continuous monitoring system was inoperable or out-of-control during the reporting period.

(n) Each owner or operator of an affected source under this subpart shall submit semiannual compliance reports with the information specified in paragraph (l) or (m) of this section to the Administrator according to the requirements in § 63.13. Beginning on May 8, 2027, or once the report template for this subpart has been available on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, you must submit all subsequent semiannual compliance reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in § 63.9(k), except any medium submitted through mail must be sent to the attention of the Gasoline Distribution Sector Lead. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

■ 14. Section 63.429 is amended by revising paragraph (c) introductory text and adding paragraph (c)(5) to read as follows:

§ 63.429 Implementation and enforcement.

* * * * *

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (5) of this section.

* * * * *

(5) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

■ 15. Table 1 to subpart R of part 63 is revised to read as follows:

TABLE 1 TO SUBPART R OF PART 63—GENERAL PROVISIONS APPLICABILITY TO THIS SUBPART

Reference	Applies to this subpart	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	Section reserved.
63.1(a)(6)	Yes.	
63.1(a)(7) through (9)	No	Sections reserved.
63.1(a)(10)	Yes.	
63.1(a)(11)	Yes.	
63.1(a)(12)	Yes.	
63.1(b)(1)	No	This subpart specifies applicability in § 63.420.
63.1(b)(2)	Yes.	
63.1(b)(3)	Yes	Except this subpart specifies additional reporting and recordkeeping for some large area sources in § 63.428. These additional requirements only apply prior to the date the applicability equations are no longer applicable.
63.1(c)(1)	Yes.	
63.1(c)(2)	Yes	Some small sources are not subject to this subpart.
63.1(c)(3)	No	Section reserved.
63.1(c)(4)	No	Section reserved.
63.1(c)(5)	Yes.	
63.1(c)(6)	Yes.	
63.1(d)	No	Section reserved.
63.1(e)	Yes.	

Table 1 to Subpart R of Part 63—General Provisions Applicability to This Subpart—Continued

Reference	Applies to this subpart	Comment
63.2	Yes	Additional definitions in § 63.421.
63.3(a)–(c)	Yes.	
63.4(a)(1) and (2)	Yes.	
63.4(a)(3) through (5)	No	Sections reserved.
63.4(b)	Yes.	
63.4(c)	Yes.	
63.5(a)(1)	Yes.	
63.5(a)(2)	Yes.	
63.5(b)(1)	Yes.	
63.5(b)(2)	No	Section reserved.
63.5(b)(3)	Yes.	
63.5(b)(4)	Yes.	
63.5(b)(5)	No	Section reserved.
63.5(b)(6)	Yes.	
63.5(c)	No	Section reserved.
63.5(d)(1)	Yes.	
63.5(d)(2)	Yes.	
63.5(d)(3)	Yes.	
63.5(d)(4)	Yes.	
63.5(e)	Yes.	
63.5(f)(1)	Yes.	
63.5(f)(2)	Yes.	
63.6(a)	Yes.	
63.6(b)(1)	Yes.	
63.6(b)(2)	Yes.	
63.6(b)(3)	Yes.	
63.6(b)(4)	Yes.	
63.6(b)(5)	Yes.	
63.6(b)(6)	No	Section reserved.
63.6(b)(7)	Yes.	
63.6(c)(1)	No	This subpart specifies the compliance date.
63.6(c)(2)	Yes.	
63.6(c)(3) and (4)	No	Sections reserved.
63.6(c)(5)	Yes.	
63.6(d)	No	Section reserved.
63.6(e)	No	See § 62.420(k) for general duty requirement.
63.6(f)(1)	No.	
63.6(f)(2)	Yes.	
63.6(f)(3)	Yes.	
63.6(g)	Yes.	
63.6(h)	No	This subpart does not require COMS; this subpart specifies requirements for visible emissions observations for flares.
63.6(i)(1) through (14)	Yes.	
63.6(i)(15)	No	Section reserved.
63.6(i)(16)	Yes.	
63.6(j)	Yes.	
63.7(a)(1)	Yes.	
63.7(a)(2)	Yes.	
63.7(a)(3)	Yes.	
63.7(a)(4)	Yes.	
63.7(b)	Yes.	
63.7(c)	Yes.	
63.7(d)	Yes.	
63.7(e)(1)	No	This subpart specifies performance test conditions.
63.7(e)(2)	Yes.	
63.7(e)(3)	Yes.	
63.7(e)(4)	Yes.	
63.7(f)	Yes.	
63.7(g)	Yes	Except this subpart specifies how and when the performance test and performance evaluation results are reported.
63.7(h)	Yes.	
63.8(a)(1)	Yes.	
63.8(a)(2)	Yes.	
63.8(a)(3)	No	Section reserved.
63.8(a)(4)	Yes.	
63.8(b)(1)	Yes.	
63.8(b)(2)	Yes.	
63.8(b)(3)	Yes.	
63.8(c)(1) introductory text	Yes.	
63.8(c)(1)(i)	No.	
63.8(c)(1)(ii)	Yes.	
63.8(c)(1)(iii)	No.	

TABLE 1 TO SUBPART R OF PART 63—GENERAL PROVISIONS APPLICABILITY TO THIS SUBPART—Continued

Reference	Applies to this subpart	Comment
63.8(c)(2)	Yes.	
63.8(c)(3)	Yes.	
63.8(c)(4)	Yes.	
63.8(c)(5)	No	This subpart does not require COMS.
63.8(c)(6) through (8)	Yes.	
63.8(d)(1) and (2)	Yes.	
63.8(d)(3)	No	This subpart specifies CMS records requirements.
63.8(e)	Yes	Except this subpart specifies how and when the performance evaluation results are reported.
63.8(f)(1) through (5)	Yes.	
63.8(f)(6)	Yes.	
63.8(g)	Yes.	
63.9(a)	Yes.	
63.9(b)(1)	Yes.	
63.9(b)(2)	Yes	Except this subpart allows additional time for existing sources to submit initial notification. Section 63.428(a) specifies submittal by 1 year after being subject to the rule or December 16, 1996, whichever is later.
63.9(b)(3)	No	Section reserved.
63.9(b)(4)	Yes.	
63.9(b)(5)	Yes.	
63.9(c)	Yes.	
63.9(d)	Yes.	
63.9(e)	Yes.	
63.9(f)	No.	
63.9(g)	Yes.	
63.9(h)(1) through (3)	Yes	Except this subpart specifies how to submit the Notification of Compliance Status.
63.9(h)(4)	No	Section reserved.
63.9(h)(5) and (6)	Yes.	
63.9(i)	Yes.	
63.9(j)	Yes.	
63.9(k)	Yes.	
63.10(a)	Yes.	
63.10(b)(1)	Yes.	
63.10(b)(2)(i), (ii), (iv), and (v)	No	This subpart specifies recordkeeping requirements for deviations.
63.10(b)(2)(iii) and (vi) through (xiv)	Yes.	
63.10(b)(3)	Yes.	
63.10(c)(1)	Yes.	
63.10(c)(2) through (4)	No	Sections reserved.
63.10(c)(5) through (8)	Yes.	
63.10(c)(9)	No.	Section reserved.
63.10(c)(10) through (14)	Yes.	
63.10(c)(15)	No.	
63.10(d)(1)	Yes.	
63.10(d)(2)	No	This subpart specifies how and when the performance test results are reported.
63.10(d)(3)	No	This subpart specifies reporting requirements for visible emissions observations for flares.
63.10(d)(4)	Yes.	
63.10(d)(5)	No.	
63.10(e)(1)	Yes.	
63.10(e)(2) through (4)	No	This subpart specifies reporting requirements for CMS and continuous opacity monitoring systems.
63.10(f)	Yes.	
63.11(a) and (b)	Yes	Except these provisions no longer apply upon compliance with the provisions in §§ 63.422(b)(2) and 63.425(d)(2) for flares to meet the requirements specified in §§ 60.502a(c)(3) and 60.504a(c) of this chapter.
63.11(c), (d), and (e)	Yes	Except these provisions do not apply to monitoring required under § 63.425(b)(1) or (c)(1) and these provisions no longer apply upon compliance with the provisions in § 63.424(c).
63.12	Yes.	
63.13	Yes.	
63.14	Yes.	
63.15	Yes.	
63.16	Yes.	

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2002–0083; FRL–5919.1–02–OAR]

RIN 2060–AV82

National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing Facilities Technology Review

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA or the Agency) is finalizing amendments to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Manufacturing Facilities to regulate hazardous air pollutant (HAP) emissions. The amendments include: HAP from unmeasured fugitive and intermittent particulate (UFIP) sources previously not regulated by the NESHAP; previously unregulated HAP for sinter plants:; previously unregulated pollutants for blast furnace (BF) stoves and basic oxygen process furnaces (BOPFs) primary control devices; and previously unregulated pollutants for BF primary control devices. We are also finalizing an update to the technology review for this source category.

DATES: This final rule is effective June 3, 2024. The incorporation by reference (IBR) of material publications listed in the rule is approved by the Director of the Federal Register (FR) beginning June 3, 2024. The incorporation by reference (IBR) of certain other material listed in the rule was approved by the Director of the Federal Register (FR) as of July 13, 2020.

ADDRESSES: The EPA established a docket for this action under Docket ID No. EPA–HQ–OAR–2002–0083. All documents in the docket are listed on the *https://www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and is publicly available only in hard copy. With the exception of such materials, publicly available docket materials are available electronically in *https://www.regulations.gov/* or in hard copy at the EPA Docket Center, Room 3334, WJC West Building, 1301 Constitution Avenue NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact Katie Boaggio, Sector Policies and Programs Division (D243–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–2223; email address: *boaggio.katie@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. Throughout this document the use of ''we,'' ''us,'' or ''our'' is intended to refer to the EPA. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACI	activated carbon injection
BF	blast furnace
BOPF	basic oxygen process furnace
BTF	Beyond-the-Floor
CAA	Clean Air Act
CBI	Confidential Business Information
COS	Carbonyl Sulfide
CFR	Code of Federal Regulations
D/F	dioxins and furans
EAV	equivalent annualized value
EJ	environmental justice
EPA	Environmental Protection Agency
HAP	hazardous air pollutant(s)
HCl	hydrochloric acid
HF	hydrogen fluoride
HMTDS	hot metal transfer, desulfurization, and skimming
ICR	Information Collection Request
II&S	Integrated Iron and Steel
km	kilometer
MACT	maximum achievable control technology
NESHAP	national emission standards for hazardous air pollutants
NTTAA	National Technology Transfer and Advancement Act
OAQPS	Office of Air Quality Planning and Standards
OMB	Office of Management and Budget
PAH	polycyclic aromatic hydrocarbons
PM	particulate matter
PBT	persistent, bioaccumulative, and toxic
PRA	Paperwork Reduction Act
PV	present value
RFA	Regulatory Flexibility Act
RTR	residual risk and technology review
SSM	startup, shutdown, and malfunction
THC	total hydrocarbons
TEQ	toxic equivalency
tpy	tons per year
UFIP	unmeasured fugitive and intermittent particulate
UMRA	Unfunded Mandates Reform Act
UPL	upper prediction limit
VCS	voluntary consensus standards
VE	visible emissions
VOC	volatile organic compound
WP	work practice

Organization of this document. The information in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

The EPA set maximum achievable control technology (MACT) standards for the Integrated Iron and Steel Manufacturing Facilities major source category in 2003 (68 FR 27645) under 40 CFR part 63, subpart FFFFF and completed a residual risk and technology review final rule in July 2020 (85 FR 42074). The purpose of this rule is to (1) fulfill the EPA's statutory obligations pursuant to CAA section 112(d)(6); *see Louisiana Environmental Action Network* v. *EPA,* 955 F.3d 1088 (D.C. Cir. 2020) (''*LEAN*''), and (2) improve the emissions standards for this source category based on new information regarding developments in practices, processes, and control technologies.

2. Summary of the Major Provisions of the Regulatory Action

To comply with CAA section 112, we are finalizing: (1) new emissions limits based on MACT for five currently unregulated HAP (COS, CS_2, Hg, HCl, and HF) from the sinter plants located at integrated iron and steel manufacturing facilities; and (2) new MACT standards, in the form of opacity limits and work practice (WP) standards, for five unregulated sources of UFIP emissions: Unplanned Bleeder Valve Openings, Planned Bleeder Valve Openings, Slag Pits, Beaching, and Bell Leaks. In this context, opacity is a measure of the amount of light that is blocked or absorbed by an air pollution plume. The components of air pollution that block or absorb light are primarily particulate matter (PM). An opacity level of 0 percent means that plumes of air pollution do not block or absorb light and are fully transparent (*i.e.,* no visible emissions), while an opacity of 100 percent means that plumes are dense and block all light (*i.e.,* the trained observer or special camera cannot see any background behind the plume). Observers are trained and certified using smoke generators which produce known opacity levels, and periodic recertification is required every six months. More details regarding the EPA approved method for opacity readings by a trained observer are available at the following website: *https://www.epa.gov/emc/method-9-visual-opacity.* Alternatively, opacity can be observed with special cameras following a specific method (known as the digital camera opacity technique (DCOT), 40 CFR 63.7823), and those images interpreted by trained individuals. For the Integrated Iron and Steel Manufacturing sector (and a number of other metals processing and production sectors), a significant portion of the emitted PM is composed of HAP metals (such as arsenic, lead, manganese, and chromium) that are primarily emitted in particulate form as demonstrated in the emissions tests available in the docket for this action. Therefore, for the Integrated Iron and Steel Manufacturing sector, as well as several other industry sectors, PM and opacity serve as surrogates for particulate HAP metals.

We are also finalizing new emissions limits for three unregulated pollutants for BF stoves and BOPFs: THC (as a surrogate for non-dioxin and non-furan organic HAP), HCl, and D/F; and for two unregulated pollutants for BFs: THC (as a surrogate for non-dioxin and non-furan organic HAP) and HCl. In this action, pursuant to CAA section 112(d)(6), we are also finalizing: (1) work practice standards for the basic oxygen process furnace (BOPF) shops; (2) a requirement that facilities conduct Method 9 readings two times per month at the BOPF Shop and BF casthouse; (3) a fenceline monitoring requirement for chromium to help ensure the work practices and opacity limits are achieving the anticipated reductions; and (4) revised standards for D/F and PAHs from sinter plants to reflect the installation and operation of activated carbon injection (ACI) technology. At this time, we are not finalizing the proposed revised opacity limits for the BOPF or the BF casthouse, as explained later in this preamble.

3. Costs and Benefits

To meet the requirements of E.O. 12866, the EPA projected the emissions reductions, costs, and benefits that may result from the final rule. These results are presented in detail in the regulatory impact analysis (RIA) accompanying this final rule developed in response to E.O. 12866. The final rule is significant under E.O. 12866 Section 3(f)(1), as amended by E.O. 14094, due to the monetized benefits of fine particulate matter ($PM_{2.5}$) reductions likely to result from the UFIP emissions standards included in the final rule. The RIA, which is available in the docket for this action, focuses on the elements of the final rule that are likely to result in quantifiable cost or emissions changes compared to a baseline without these regulatory requirements. We estimated the cost, emissions, and benefit impacts for the 2026 to 2035 period, discounted to 2024. We show the present value (PV) and equivalent annualized value (EAV) of costs, benefits, and net benefits of this action in 2022 dollars. The EAV represents a flow of constant annual values that would yield a sum equivalent to the PV. The EAV represents the value of a typical cost or benefit for each year of the analysis, consistent with the estimate of the PV, in contrast to year-specific estimates.

The initial analysis year in the RIA is 2026 because we assume that will be the first year of full implementation of the rule. We are finalizing that facilities will have 1 year to demonstrate compliance with the relevant standards following promulgation. This analysis assumes that full compliance with the standards will occur in early 2025. Therefore, the first full year of impacts will occur in 2026. The final analysis year is 2035, which allows us to provide ten years of projected impacts after the rule takes effect.

The cost analysis presented in the RIA reflects a nationwide engineering analysis of compliance cost and emissions reductions. Impacts are calculated by setting parameters on how and when affected facilities are assumed to respond to a particular regulatory regime, calculating estimated cost and emissions impact estimates for each facility, differencing from the baseline scenario, and then summing to the desired level of aggregation.

The EPA expects health benefits due to the emissions reductions projected from the rule. We expect that HAP emission reductions will improve health and welfare associated with reduced exposure for those affected by these emissions. In addition, the EPA expects that $PM_{2.5}$ emission reductions that will occur concurrent with the reductions in HAP emissions will improve air quality and are likely to improve health and welfare associated with exposure to $PM_{2.5}$ and HAP. For the RIA, the EPA monetized benefits associated with premature mortality and morbidity from reduced exposure to $PM_{2.5}$. Discussion of both the monetized and non-monetized benefits can be found in Chapter 4 of the RIA.

Table 1 presents the emission changes and the PV and EAV of the projected monetized benefits, compliance costs, and net benefits over the 2026 to 2035 period under the rule. All discounting of impacts presented uses social discount rates of 3 and 7 percent.

TABLE 1—MONETIZED BENEFITS, COSTS, NET BENEFITS, AND EMISSIONS REDUCTIONS OF THE FINAL NESHAP SUBPART FFFFF AMENDMENTS, 2026 THROUGH 2035 [a]

[Dollar estimates in millions of 2022 dollars, discounted to 2024]

	3 Percent discount rate		7 Percent discount rate	
	PV	EAV	PV	EAV
Benefits [b]	$1,800 and $3,700	$200 and $420	$1,200 and $2,600	$170 and $340.
Compliance Costs	$45	$5.3	$36	$5.1.
Net Benefits	$1,800 and $3,700	$190 and $410	$1,200 and $2,600	$160 and $330.
Emissions Reductions (short tons)	2026–2035 Total			
HAP	640			
PM	18,000			
$PM_{2.5}$	4,700			
Non-monetized Benefits in this Table	HAP benefits from reducing 640 short tons of HAP from 2026–2035. Non-health benefits from reducing 18,000 tons of PM, of which 4,700 tons is $PM_{2.5}$, from 2026–2035. Benefits from reducing HCl, HF, Hg, D/F TEQ, COS, and CS2. Visibility benefits. Reduced vegetation effects.			

[a] Totals may not sum due to independent rounding. Numbers rounded to two significant digits unless otherwise noted.

[b] Monetized benefits include health benefits associated with reductions in $PM_{2.5}$ emissions. The monetized health benefits are quantified using two alternative concentration-response relationships from the Di et al. (2016) and Turner et al. (2017) studies and presented at real discount rates of 3 and 7 percent. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. Benefits from HAP reductions remain unmonetized and are thus not reflected in the table.

B. Does this action apply to me?

Table 2 of this preamble lists the NESHAP and associated regulated industrial source category that is the subject of this final rule. Table 2 is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that this final action is likely to affect. The final standards are directly applicable to the affected sources. Federal, state, local, and Tribal government entities are not affected by this final action. As defined in the *Initial List of Categories of Sources Under Section 112(c)(1) of the Clean Air Act Amendments of 1990* (see 57 FR 31576; July 16, 1992) and *Documentation for Developing the Initial Source Category List, Final Report* (see EPA–450/3–91–030; July 1992), the Integrated Iron and Steel Manufacturing Facilities source category is any facility engaged in producing steel from iron ore. Integrated iron and steel manufacturing includes the following processes: sinter production, iron production, iron preparation (hot metal desulfurization), and steel production. The iron production process includes the production of iron in BFs by the reduction of iron-bearing materials with a hot gas. The steel production process occurs in the BOPFs where hot liquid iron from the BF is loaded (*i.e.,* charged) into the BOPF along with coke, lime, alloys, and steel scrap, and includes blowing oxygen into the furnace through a lance resulting in oxidation reactions to produce steel.

TABLE 2—NESHAP AND INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS FINAL ACTION

Source category	NESHAP	NAICS code [1]
Integrated Iron and Steel Manufacturing Facilities	40 CFR part 63, subpart FFFFF	331110

[1] North American Industry Classification System.

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action is available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this final action at *https://www.epa.gov/stationary-sources-air-pollution/integrated-iron-and-steel-manufacturing-national-emission-standards.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rule and key technical documents at this same website.

D. Judicial Review and Administrative Reconsideration

Under Clean Air Act (CAA) section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) by June 3, 2024. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. This section also provides a mechanism for the EPA to reconsider the rule if the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within the period for public comment or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule. Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, WJC South Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Background

A. What is the statutory authority for this action?

This action finalizes amendments to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for the Integrated Iron and Steel Manufacturing Facilities source category. The statutory authority for this action is provided by section 112 of the CAA, as amended (42 U.S.C. 7401, *et seq.*). In the first stage of the CAA section 112 standard-setting process, the EPA promulgates technology-based standards under CAA section 112(d) for categories of sources identified as emitting one or more of the HAP listed in CAA section 112(b). Sources of HAP emissions are either major sources or area sources, and CAA section 112 establishes different requirements for major source standards and area source standards. ''Major sources'' are those that emit or have the potential to emit 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of any combination of HAP. All other sources are ''area sources.''

For major sources, CAA section 112(d)(2) provides that the technology-based NESHAP must reflect the maximum degree of emission reductions of HAP achievable after considering cost, energy requirements, and non-air quality health and environmental impacts. These standards are commonly referred to as MACT standards. CAA section 112(d)(3) also establishes a minimum control level for MACT standards, known as the MACT ''floor.'' In certain instances, as provided in CAA section 112(h), if it is the judgment of the Administrator that it is not feasible to prescribe or enforce an emission standard, the EPA may set work practice standards in lieu of numerical emission standards. The EPA must also consider control options that are more stringent than the floor, commonly referred to as ''beyond-the-floor'' (BTF) standards.

CAA section 112(d)(6) requires the EPA to review standards promulgated under CAA section 112 and revise them ''as necessary (taking into account developments in practices, processes, and control technologies)'' no less often than every eight years. While conducting this review, which we call the ''technology review,'' the EPA is not required to recalculate the MACT floors that were established during earlier rulemakings. *Nat. Resources Def. Council, et al.* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008); *Ass'n of Battery Recyclers, Inc.* v. *EPA,* 716 F.3d 667 (D.C. Cir. 2013). The EPA may consider cost in deciding whether to revise the standards pursuant to CAA section 112(d)(6). However, costs may not be considered when setting the MACT floor and may only be considered when determining whether beyond-the-floor standards are appropriate. *See* CAA section 112(d)(3).

CAA section 112(f) requires the EPA to determine whether promulgation of additional standards is needed to provide an ample margin of safety to protect public health or to prevent an adverse environmental effect. This review is known as the ''residual risk review,'' and it must occur within eight years after promulgation of the standards. When the EPA conducts the ''technology review'' together with the ''residual risk review,'' the combined review is known as a ''risk and technology review'' or ''RTR.''

The EPA initially promulgated the Integrated Iron and Steel Manufacturing Facilities NESHAP on May 20, 2003 (68 FR 27645), codified at title 40, part 63, subpart FFFFF (the NESHAP). The rule was amended on July 13, 2006 (71 FR 39579). The amendments added a new compliance option, revised emission limitations, reduced the frequency of repeat performance tests for certain emission units, added corrective action requirements, and clarified monitoring, recordkeeping, and reporting requirements.

In 2015, a coalition of environmental advocacy groups filed a lawsuit to compel the EPA to fulfill its statutory duty to conduct the CAA sections 112(d) and 112(f)(2) reviews of 21 NESHAPs, including Integrated Iron and Steel Manufacturing Facilities. As a result of that litigation, the EPA was required by court order to complete the RTR for the Integrated Iron and Steel Manufacturing Facilities source category by May 5, 2020. *California Communities Against Toxics* v. *Wheeler,* No. 1:15–00512, Order (D.D.C. March 13, 2017, as modified Feb. 20, 2020). The resulting RTR conducted for the Integrated Iron and Steel Manufacturing Facilities NESHAP was signed on May 4, 2020. 85 FR 42074 (July 13, 2020).

In an April 2020 decision by the U.S. Court of Appeals for the District of Columbia Circuit, on a petition for review of the EPA's NESHAP rulemaking for a different source category (pulp mill combustion sources), the court held that the EPA has an obligation to address all unregulated HAP emissions from a source category when the Agency conducts the eight-year technology review required by CAA section 112(d)(6). *Louisiana Environmental Action Network* v. *EPA,* 955 F.3d 1088, 1098–99 (''*LEAN*''). The parties in *California Communities Against Toxics* thereafter filed a joint motion to extend those deadlines to allow the EPA to revise the rules in accordance with the *LEAN* opinion. The court granted the motion, setting a new deadline for this rule of October 26, 2023. Order, *California Communities Against Toxics,* No. 15–512 (D.D.C. April 14, 2021). Based on further negotiation between the parties, the deadline for this final rule was changed to March 11, 2024. Minute Order, *California Communities Against Toxics,* No. 15–512 (D.D.C. Sept. 20, 2023).

In September 2021, industry and environmental advocacy groups filed petitions for review of the 2020 Integrated Iron and Steel Manufacturing Facilities final rule, and these petitions have been consolidated. *American Iron and Steel Inst., et al.* v. *EPA,* No. 20–1354 (D.C. Cir.); *Clean Air Council, et al.* v. *EPA,* No. 20–1355 (D.C. Cir.). The consolidated case is being held in abeyance pending the promulgation of this final rule. *See EPA's Unopposed Mot. to Hold Cases in Abeyance,* No. 20–1354 (consol.) (D.C. Cir.), Dkt. No. 2028131 (reporting to the D.C. Circuit the March 11, 2024 final rule deadline); Order, *American Iron and Steel Inst.,* No. 20–1354 (consol.) (D.C. Cir. Dec. 7, 2022).

In light of this litigation history, this final rule addresses multiple issues, including: (1) new standards to address previously unregulated emissions of HAP from the Integrated Iron and Steel Manufacturing Facilities source category pursuant to the *LEAN* decision and CAA sections 112(d)(2) and (3) and 112(h) and, (2) revised standards for a few currently regulated HAP, as well as fenceline monitoring requirements, pursuant to the CAA section 112(d)(6) technology review.

B. What is the source category and how does the current NESHAP regulate its HAP emissions?

As described above, the Integrated Iron and Steel Manufacturing Facilities source category includes any facility engaged in producing steel from refined iron ore (also known as taconite pellets). These facilities first produce iron from iron ore taconite pellets, sinter, coke, and other raw materials using blast furnaces (BFs), then produce steel from the hot liquid iron produced from the blast furnaces, along with coke, lime, alloys, steel scrap, and other raw materials using basic oxygen process furnaces (BOPFs). Integrated iron and steel manufacturing includes the following processes: sinter production, iron production, iron preparation (hot metal desulfurization), and steel production. The iron production process includes the production of iron in BFs by the reduction of iron-bearing materials with a very hot gas. The steel production process includes BOPFs and ladle metallurgy operations. Currently there are eight operating facilities in this source category.

The main sources of HAP emissions from integrated iron and steel manufacturing are the BF; BF stove; BOPF; hot metal transfer, desulfurization, and skimming (HMTDS) operations; ladle metallurgy operations; sinter plant windbox; sinter plant discharge end; and sinter cooler. All eight facilities have BFs, BF stoves, BOPFs, HMTDS operations, and ladle metallurgy operations. However, only three facilities have sinter plants and only two facilities with currently operating sinter plants.

The following are descriptions of the BF, BOPF, and sinter plants:

- The BF is a key integrated iron and steel process unit where molten iron is produced from raw materials such as iron ore, lime, sinter, coal and coke.
- The BOPF is a key integrated iron and steel process unit where steel is made from molten iron, scrap steel, lime, dolomite, coal, coke, and alloys.
- Sinter is derived from material formed in the bottom of the blast furnace, composed of oily scale, blast furnace sludge, and coke breeze, along with tarry material and oil absorbed from the sump in which the sinter is recovered. The sinter plant processes the waste that would otherwise be landfilled so that iron and other valuable materials can be re-used in the blast furnace. Only three sources covered by the Integrated Iron and Steel Manufacturing Facility category have sinter plants, down from nine facilities with sinter plants in 2003.

In addition to point sources, the EPA identified seven UFIP emission sources for this source category, including BF bleeder valve unplanned openings, BF bleeder valve planned openings, BF bell leaks, BF casthouse fugitives, BF iron beaching, BF and BOPF slag handling and storage operations, and BOPF shop fugitives. These UFIP emission sources were identified by observation of visible plumes by EPA regional staff during onsite source inspections and were subsequently investigated to determine the causes and any possible methods for reductions. These inspections are documented in numerous reports and photographs between 2008 and the present.[1] The NESHAP regulates two of these sources—BF casthouse fugitives and BOPF shop fugitives—with opacity limits.

The following are descriptions of the main process units and the seven UFIP sources:

- The BF is a key integrated iron and steel process unit where molten iron is produced from raw materials such as iron ore, lime, sinter, coal and coke.
- The BOPF is a key integrated iron and steel process unit where steel is made from molten iron, scrap steel, lime, dolomite, coal, coke, and alloys.
- Sinter is derived from material formed in the bottom of the blast furnace, composed of oily scale, blast furnace sludge, and coke breeze, along with tarry material and oil absorbed from the sump in which the sinter is recovered. The sinter plant processes the waste that would otherwise be landfilled so that iron and other valuable materials can be re-used in the blast furnace. Only three sources covered by the Integrated Iron and Steel Manufacturing Facility category have sinter plants, down from nine facilities with sinter plants in 2003.
- The BOPF shop is the structure that houses the entire BOPF and auxiliary activities, such as hot iron transfer, skimming, and desulfurization of the iron and ladle metallurgy operations, which generate fugitive emissions.
- The BF casthouse is the structure that houses the lower portion of the BF and encloses the tapping operation and the iron and slag transport operations, which generate fugitive emissions.
- The bleeder valve is a device at the top of the BF that, when open, relieves BF internal pressure to the ambient air. The valve can operate as both a self-actuating safety device to relieve excess pressure and as an operator-initiated instrument for process control. A bleeder valve opening means any opening of the BF bleeder valve, which allows gas and/or PM to flow past the sealing seat. Multiple openings and closings of a bleeder valve that occur within a 30-minute period could be considered a single bleeder valve opening. There are two types of openings, planned and unplanned.
- A planned bleeder valve opening means an opening that is initiated by an operator as part of a furnace startup, shutdown, or temporary idling for maintenance action. Operators can prepare the furnace for planned openings to minimize or eliminate emissions from the bleeder valves.
- An unplanned bleeder valve opening means an opening that is not planned and is caused by excess pressure within the furnace. The pressure buildup can occur when raw materials do not descend smoothly after being charged at the top of the BF and accumulate in large masses within the furnace. When the large masses finally dislodge (slip) due to their weight, a pressure surge results.
- Slag is a by-product containing impurities that is released from the BF or BOPF along with molten iron when the BF or BOPF is tapped from the bottom of the furnace. The slag is less dense than iron and, therefore, floats on top of the iron. Slag is removed by skimmers and then transported to open pits to cool to enable later removal. Usually there is one slag pit for every BF or BOPF.
- Iron beaching occurs when iron from a BF cannot be charged to the BOPF because of problems in steelmaking units; the hot molten iron from the BF is placed onto the ground, in some cases within a three-sided structure.
- The BF bells are part of the charging system on top of the furnace that allows for materials to be loaded into the furnace or next bell (as in the case of small bells) without letting BF gas escape. It is a two-bell system, where a smaller bell is above a larger bell. These bells must be tightly sealed to the blast furnace when not in use for charging, so that BF gas and uncontrolled emissions do not escape to the atmosphere. Over time, the surfaces that seal the bells wear down and need to be repaired or replaced. If these seals are not repaired or replaced in a timely manner, emissions of HAP and PM can increase significantly.

In the 2020 final rule, the Agency found that risks due to emissions of air toxics from this source category were

---

[1] *See, e.g.,* communications between B. Dickens and P. Miller, U.S. EPA Region V, Chicago, IL, with D.L. Jones, U.S. EPA, Office of Air Quality Planning and Standards, Office of Air and Radiation, 2015–2018. See also *Ample Margin of Safety for Nonpoint Sources in the II&S Industry.* Both documents are available in the docket to this rule.

acceptable and concluded that the NESHAP provided an ample margin of safety to protect public health. Although the 2020 NESHAP found the risks acceptable and no new requirements should be imposed, new data was collected via a CAA section 114 request to industry after re-opening the rule, due to the *LEAN* court decision. These new data necessitated technology review updates, in addition to establishing new MACT standards for unregulated HAPs pursuant to the *LEAN* court decision. Under the technology review in the 2020 RTR, the EPA found no developments in practices, processes, or control technologies that necessitated revision of the standards at that time. However, in response to a 2004 administrative petition for reconsideration of the 2003 NESHAP, the 2020 final rule promulgated a new MACT emissions limit for mercury (0.00026 lbs mercury/ton scrap metal) with two compliance options: (1) conduct annual compliance tests (to demonstrate compliance with the MACT limit); or (2) confirm that the facility obtains their auto scrap from suppliers that participate in the National Vehicle Mercury Switch Recovery Program (NVMRP) or another approved mercury switch removal program or that the facility only uses scrap that does not contain mercury switches. We also removed exemptions for periods of startup, shutdown, and malfunction (SSM) consistent with *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008); clarified that the emissions standards apply at all times; added electronic reporting of performance test results and compliance reports; and made minor corrections and clarifications for a few other rule provisions. All documents used to develop the previous 2003, 2006, and 2020 final rules can be found in either the legacy docket, A–2000–44, or the electronic docket, EPA–HQ–OAR–2002–0083.

The NESHAP includes emissions limits for PM and opacity standards—both of which are surrogates for non-mercury PM HAP metals—for furnaces and sinter plants. To support the continued use of PM as a surrogate for certain non-mercury HAP metals, we considered the holding in *National Lime Ass'n* v. *EPA,* 233 F.3d 625 (D.C. Cir. 2000). In considering whether the EPA may use PM, a criteria pollutant, as a surrogate for metal HAP, the D.C. Circuit stated that the EPA ''may use a surrogate to regulate hazardous pollutants if it is 'reasonable' to do so,'' *id.* at 637, establishing criteria for determining whether the use of PM as a surrogate for non-mercury metal HAP was reasonable. The court found that PM is a reasonable surrogate for HAP if: (1) ''HAP metals are invariably present'' in the source's PM,'' *id.*; (2) the ''source's PM control technology indiscriminately captures HAP metals along with other particulates,'' *id.* at 639; and (3) ''PM control is the only means by which facilities 'achieve' reductions in HAP metal emissions,'' *id.* If these criteria are satisfied and the PM emission standards reflect what the best sources achieve in compliance with CAA section 112(d)(3), then ''EPA is under no obligation to achieve a particular numerical reduction in HAP metal emissions.'' *Id.* The EPA has established and promulgated PM limits as a surrogate for particulate HAP metals successfully in several NESHAP regulations, including Ferroalloys Production (80 FR 37366, June 30, 2015), Taconite Iron Ore Processing (68 FR 61868), and Primary Copper Smelting (67 FR 40478, June 12, 2002).

The NESHAP also includes an operating limit for the oil content of the sinter plant feedstock or, as an alternative, an emissions limit for volatile organic compounds (VOC) for the sinter plant windbox exhaust stream. The oil limit, and the alternative VOC limit, serve as surrogates for all organic HAP. Moreover, the NESHAP includes an emissions limit for mercury emissions from the BOPF Group, which is the collection of BOPF shop steelmaking operating units and their control devices including the BOPF primary emission control system, BOPF secondary control system, ladle metallurgy units, and hot metal transfer, desulfurization and slag skimming units.

C. What changes did we propose for the Integrated Iron and Steel Manufacturing Facilities source category?

On July 31, 2023, the EPA published a proposal in the **Federal Register** to set standards to regulate HAP emissions from five UFIP sources that were not previously regulated by the NESHAP: Bell Leaks, Unplanned Bleeder Valve Openings, Planned Bleeder Valve Openings, Slag Pits, and Beaching. For sinter plants, we proposed standards for five previously unregulated HAP: COS, CS_2, Hg, HCl, and HF. For BF stoves and BOPFs, we proposed standards for three previously unregulated pollutants: THC (as a surrogate for non-dioxin and non-furan organic HAP), HCl, and D/F. And for BFs, we proposed standards for two previously unregulated pollutants: THC (as a surrogate for non-dioxin and non-furan organic HAP) and HCl.

As an update to the technology review, we proposed to revise the previous BOPF shop fugitive 20 percent opacity limit to a 5 percent opacity limit and require specific work practices; revise the current BF casthouse fugitive 20 percent opacity limit to a 5 percent opacity limit; and revise the current standards for D/F and PAH for sinter plants to reflect current control performance of sinter plants for these HAP. We also proposed a fenceline monitoring requirement for Cr, including a requirement that if a monitor exceeds the proposed Cr action level, the facility would need to conduct a root cause analysis and take corrective action to lower emissions.

III. What is the rationale for our final decisions and amendments for the Integrated Iron and Steel Manufacturing Facilities source category?

For each issue, this section provides a description of what we proposed and what we are finalizing, a summary of key comments and responses, and the EPA's rationale for the final decisions and amendments. For all comments not discussed in this preamble, comment summaries and the EPA's responses can be found in the document, *Summary of Public Comments and Responses for Proposed Amendments to the National Emission Standards for Hazardous Air Pollutants for Integrated Iron and Steel Manufacturing Facilities,* which is available in the docket for this action. This document is also referred to as the Response to Comments (RTC) in subsequent sections of this preamble.

A. Standards To Address Five Unregulated UFIP Sources for Both New and Existing Sources

1. What did we propose for the five previously unregulated UFIP sources?

a. BF Unplanned Bleeder Valve Openings

Based on the data we received through the CAA section 114 requests, the average number of unplanned openings of the best performing five furnaces in the source category is 5 unplanned openings per year. Therefore, we proposed an operational limit of five unplanned openings per year per furnace for existing sources, which was an estimate of the MACT floor level of performance for existing sources. For new sources, we proposed an operational limit of zero unplanned openings per year because the best performing single source in our database reported zero unplanned openings for the most recent representative year.

Additionally, we proposed work practice standards that would require facilities to do the following: (1) install and operate devices (*e.g.,* stockline monitors) to continuously measure/monitor material levels in the furnace, at a minimum of three locations, using alarms to inform operators of static conditions that indicate a slip may occur and alert them that there is a need to take action to prevent the slips and unplanned openings from occurring; (2) install and operate instruments such as a thermocouple and transducer on the furnace to monitor temperature and pressure to help determine when a slip may occur; (3) install a screen to remove fine particulates from raw materials to ensure only properly-sized raw materials are charged into the BF; and (4) develop, and submit to the EPA for approval, a plan that explains how the facility will implement these requirements. Additionally, we proposed that facilities would need to report the unplanned openings (including the date, time, duration, and any corrective actions taken) in their semiannual compliance reports.

b. BF Planned Bleeder Valve Openings

Based on our evaluation of available information and pursuant to CAA section 112(d)(2) and (3), for existing sources we proposed a MACT floor limit of 8 percent opacity for any 6-minute averaging period for the BF planned bleeder valve openings. We did not propose the BTF option of 5 percent opacity for existing sources because we determined that 5 percent opacity may not be feasible for some sources on a consistent basis. For new sources, we proposed an opacity of 0 percent because based on the available data, the best performing single source had opacity of 0 percent during the planned opening. We expect that new sources will be able to configure their furnace design and operations similarly to the best performing single source which, in combination with utilizing the suggested work practices described in the document *Unmeasurable Fugitive and Intermittent Particulate Emissions and Cost Impacts for Integrated Iron and Steel Facilities under 40 CFR part 63, subpart FFFFF,* should allow them to achieve an opacity of 0 percent. We did not propose any work practices under CAA section 112(h) for the BF planned bleeder valve openings; facilities will have the flexibility to choose an appropriate approach to meet the opacity limit.

c. BF and BOPF Slag Processing, Handling, and Storage

Based on our analyses and pursuant to CAA section 112(d)(2) and (3), for existing sources we proposed a BTF opacity limit of 5 percent based on 6-minute averages for visible emissions from slag pits and during slag handling, storage, and processing. Regarding new sources, we proposed a MACT floor opacity limit of 2.5 percent based on 6-minute averages for visible emissions from slag pits and during slag handling, storage, and processing.

d. BF Bell Leaks

Based on our evaluation and pursuant to CAA section 112(d)(2) and (3), we proposed 10 percent opacity as an action level, as described below in this paragraph, for large bell leaks (not a MACT emissions limit). Along with this action level, we also proposed that the BF top will need to be observed monthly for visible emissions (VE) with EPA Method 22, 40 CFR part 60, appendix A–7, which determines the presence or absence of a visible plume, to identify leaks, and if VE are detected out of the interbell relief valve (indicating leaks from the large bell), we proposed that the facility would then need to perform EPA Method 9, 40 CFR part 60, appendix A–4, tests which determines the opacity (*i.e.,* degree to which a plume obscures the background), monthly and if opacity is greater than 10 percent (based on a 3-minute average), the large bell seals will need to be repaired or replaced within 4 months. For the small bell, we proposed that facilities will need to replace or repair seals prior to a metal throughput limit, specified by the facility, that has been proven and documented to produce no opacity from the small bells.

e. Beaching of Iron From BFs

Pursuant to CAA section 112(d)(2) and (3) and CAA section 112(h), we proposed a MACT standard that would require facilities to: (1) have full or partial enclosures for the beaching process or use CO_2 to suppress fumes; and (2) minimize the height, slope, and speed of beaching.

2. What comments did we receive on the proposed standards and, what are our responses?

a. BF Unplanned Bleeder Valve Openings

Comment: Commenters stated that in developing the proposed limit on the number of unplanned pressure release device (PRD) openings that could occur within a year, the EPA treated all BFs alike by placing them in a single category. Commenters stated that because larger BFs are able to accommodate higher internal pressures before the need for an unplanned opening, the EPA should create two separate subcategories of blast furnaces. Commenters stated that in reviewing data for unplanned PRD openings, they believed that subcategorization is appropriate and necessary if an action level or limit of any type is to be established for the number of events. In particular, commenters noted that large BFs have significantly fewer unplanned openings, where ‘‘Large BF’’ is defined as a BF with a working volume greater than 2,500 cubic meters (m^3). Commenters also stated that the EPA did not account for variability across sources and asked EPA to apply an upper prediction limit (UPL) if it were to finalize a limit on unplanned openings. Commenters stated that a 99 percent UPL analysis of the data supports limits of 52 unplanned openings for large BFs and 112 unplanned openings for small BFs.

Response: We agree with the commenter that larger BFs are able to accommodate higher internal pressure and that subcategorization based on BF size is appropriate. In this final rule, we define ‘‘large BF’’ as a BF with a working volume greater than 2,500 m^3 and are establishing separate limits on unplanned openings for large and small BF.

EPA also agrees with commenters that it is important to account for variability in the incidence of unplanned openings. Accordingly, in the final rule the EPA has decided to base the limit on the highest number of unplanned openings reported within the top five sources to ensure that we adequately account for variability, rather than the proposed approach of basing the limit on the average number of unplanned openings within the top five sources.

EPA disagrees with commenters' suggestion that it should apply a 99 percent UPL to determine the limit on unplanned openings. The EPA commonly uses the 99 percent UPL to calculate numerical emissions limits based on stack test data (*e.g.,* grams of HAP per cubic meter of stack exhaust gases). The UPL method is not appropriate to evaluate a count of unplanned openings because these are discrete events and are therefore not analogous to emissions data or test runs. In the context of this final rule, application of the UPL would therefore not appropriately reflect variability and would lead to an exceedingly high limit on unplanned openings that does not reflect the performance achieved at top-performing sources. As noted above, the EPA has instead accounted for variability in this final rule by basing the limit on the highest number of unplanned openings observed among the five top-performing sources.

b. BF Planned Bleeder Valve Openings

Comment: Commenters agreed that these opacity limits will result in HAP reductions. Accordingly, commenters supported these revisions and additions and encouraged the EPA to not weaken any of the proposed limits.

Response: EPA appreciates the support and agrees that these opacity limits for planned bleeder valve openings will result in HAP reductions.

Comment: EPA should not adopt the proposed 8% opacity limit and weekly Method 9 testing for planned openings in addition to the new work practice standards. PRD openings by operators are routinely necessary and appropriate for proper BF operation. Emissions from planned openings are exceedingly low, ranging from 1.6 tpy to 0.3 tpy, with reductions projected between 0.4 and 0.08 tpy across the entire industry. The work practice standards are expensive, with estimated cost-effectiveness based upon the proposed rule having rates ranging from $134,000/ton to $672,000/ton. No regulation of these small contributors should occur. If EPA nonetheless moves forward, there should be an action level at 15% (based on a more robust UPL analysis).

Response: Based on our evaluation of public comments and available information, pursuant to CAA section 112(d)(2) and (3) and the *LEAN* court decision, for existing sources we are promulgating a MACT Floor limit of 8 percent opacity for any 6-minute averaging period for the BF planned bleeder valve openings. The MACT floor is the least stringent standard allowed by section 112 of the Clean Air Act. For new sources, we are promulgating an opacity of 0 percent because based on the available data, the best performing single source had opacity of 0 percent during the planned opening, which we consider the MACT Floor level for new sources pursuant to CAA section 112. As we explained in the proposed rule, we determined based on evaluation of available information that emissions can be minimized from bleeder valve planned openings cost effectively by implementing various actions before the valves are opened such as: (1) tapping as much liquid (iron and slag) out of the furnace as possible; (2) removing fuel and/or stopping fuel injection into the furnace; and (3) lowering bottom pressure. However, as explained in the proposed rule preamble, we did not propose any specific work practices for the BF planned bleeder valve openings and we are maintaining the decision to not require any specific work practices for the final rule. Facilities will have the flexibility to choose an appropriate approach to meet the opacity limit.

We estimate that this standard will result in about 0.41 tpy reduction in HAP metal emissions. The estimated cost is $54,600/yr for the entire category and $6,800/yr per facility. The estimated cost effectiveness is $134,000 per ton of HAP metals.

c. BF and BOPF Slag Processing, Handling, and Storage

Comment: Commenters stated that the proposed 5 percent opacity limit for slag handling operations should not be adopted. They contend that it is virtually impossible to enclose the extremely hot slag material or to universally apply water at all times to help suppress emissions because of the volatile nature of the material and the potential for a life-threatening hazardous explosion when the water violently expands in the form of steam. Commenters stated that the EPA had ignored these important safety concerns in proposing the 5 percent opacity limit, and that the control measures the EPA had identified to meet this limit could not be reasonably utilized. Commenters also argued that even if EPA's suggested control measures were applied, a UPL analysis would result in an opacity limit of 20 percent, far exceeding the proposed 5 percent level. Commenters noted that the EPA had improperly failed to account for variability in the performance of sources by declining to apply a UPL or other statistical analysis.

Response: After considering these comments, we agree that a limit of 5 percent opacity could result in higher cost impacts than we estimated at proposal for some facilities. As described in the proposed rule **Federal Register** notice published on July 31, 2023 (88 FR 49402), the proposed 5 percent opacity limit was a beyond-the-floor limit based on the EPA's understanding at that time that emissions could be cost effectively minimized from slag pits with the application of water spray or fogging and/or other work practices such as installing wind screens, dust suppression misters, and maintaining a high moisture content of the slag during handling, storage, and processing. However, at proposal we did not account for variability and certain other factors such as weather conditions and possible safety issues. Although we still conclude that these measures can help minimize emissions, these measures might not be sufficient to consistently maintain opacity below 5 percent.

In the proposed rule FR notice, we also described a potential MACT floor opacity limit of 9 percent for existing sources which was based on the straight average of the top five performing facilities. Based on the comments submitted, the EPA is finalizing an opacity limit of 10 percent based on a MACT floor analysis for existing sources. This final limit is based on the average opacity of 9 percent reported by the five top performing facilities, but rounding up slightly to 10 percent to account for variability. The EPA has historically used the UPL approach to develop MACT limits for stack emissions of individual pollutants, but has not historically determined opacity limits using a UPL approach. The UPL calculation introduces a predictive element to the statistics in order to account for variability. However, unlike typical emissions testing, EPA Method 9 tests frequently result in values of zero, which cannot be used in the UPL calculation so this approach for accounting for variability was not used. The EPA determined that rounding the opacity from 9 percent to 10 percent sufficiently accounts for variability in this process. Therefore, in this final rule we are promulgating a 10 percent opacity limit (based on six-minute averages) for slag processing, handling, and storage. Because this 10 percent opacity limit has been achieved in practice by top performing facilities, we expect that all facilities will be able to achieve this 10 percent opacity limit by application of some or all of the work practices described above and in the proposed rule **Federal Register** notice (88 FR 49402). Other comments and responses on this issue are provided in the RTC.

d. BF Bell Leaks

Comment: Commenters expressed concerns that the proposed triggers for action for large bells are too low and that the repair and replacement time should consider lead time and operational concerns. Commenters suggested that with this in mind, the EPA could establish a 20 percent opacity action level (6-minute average) with quarterly EPA Method 9 observation requirements. Under this approach, if a facility observes opacity in excess of 20 percent, the facility should be required to investigate, make operational changes, and conduct a repair, followed by repeat testing using EPA Method 9 to confirm the efficacy of the repair. If repairs are not successful, only then would replacement obligations be triggered. Other commenters stated that if the EPA moves forward with work practice standards, the EPA should consider an alternative under which a facility would need to initiate operational or other corrective actions within five business days if an EPA Method 9 test identifies opacity of 20 percent or more. If the facility does not reduce opacity to less than 20 percent with those actions, the facility would have another five business days to initiate further operational or other corrective actions to reduce opacity to less than 20 percent. Only if the second attempt does not result in opacity of 20 percent or less would the test result be deemed a deviation requiring reporting and corrective actions, such as moving to the repair step or, if necessary, replacement of the large bell.

Response: We agree with the commenter who suggested the two-step approach for large bells is appropriate as well as the suggestion of 20% opacity instead of 10% opacity as a trigger. As discussed by the commenter, the replacement of bells is costly and there are numerous more cost-effective repair options available that can be achieved in a shorter time period to avoid full repair and replacement. This would help keep the bell repairs on a more organized schedule. Therefore, we decided to finalize a 20 percent opacity action level (instead of the proposed 10 percent opacity action level) and provide two five-business day periods to investigate the opacity trigger, as suggested by the commenter. Specifically, we changed the requirement to the following: if EPA Method 9 identifies opacity greater than 20 percent, the facility shall initiate corrective actions within five business days. If the first attempt to correct fails and EPA Method 9 again identifies that opacity is not reduced to 20 percent or lower, the facility would have another five business days to initiate further corrective actions to reduce opacity to 20 percent or lower. Only if the second attempt does not result in an opacity of 20 percent or less would it become a deviation, requiring reporting and corrective actions that we included in the proposed rule, such as moving to the repair step or, if unsuccessful, replacement of the large bell.

e. Beaching of Iron From BF's

Comment: Commenters supported the proposal to require facilities to: (1) have full or partial enclosures for the beaching process or use CO_2 to suppress fumes; and (2) minimize the height, slope, and speed of beaching. Commenters supported the addition of monitoring of vents from the partial enclosures to allow for additional information and accountability for these sources.

Response: EPA appreciates the support for the beaching requirements in the proposed rule.

Comment: Industry commenters stated that the proposed work practice standards to address already low emissions from beaching events, which the industry consistently works to minimize, would not provide meaningful reductions and would be extremely costly. Industry commenters estimated about 4 pounds per year of reduction from these proposed measures, lower than the estimates EPA provided in the final rule. Commenters also pointed out that EPA's estimated cost per ton of removal would be $15.8 million/ton and argued that this amount is unreasonable notwithstanding EPA's explanation that it must adhere to the floor provisions of the statute. Commenters stated that if EPA were to use the more accurate emissions and cost information provided by industry, the cost-effectiveness rate estimate based upon the proposed rule would be multiple times higher at $311 million/ton. Commenters also argued that EPA could reasonably interpret Section 112(d) to avoid this result.

Response: As EPA explained in the proposal preamble, as mandated by the *LEAN* court decision and CAA sections 112(d)(2), 112(d)(3), and 112(h), we proposed a MACT floor standard (which is the least stringent standard allowed by section 112 of the Clean Air Act) that would require facilities to: (1) have full or partial enclosures for the beaching process or use CO_2 to suppress fumes; and (2) minimize the height, slope, and speed of beaching. We expect this will result in a small amount of unquantified emission reductions since baseline emissions are already low (less than 1 tpy of HAP) and because most facilities are already following some or all of these work practices. Regarding costs, when EPA determines the MACT floor level of control, per the section 112 of the CAA, the EPA is obligated to determine the MACT floor level regardless of costs. It is only the potential beyond-the-floor standards for which costs become an important consideration. Nevertheless, as we mentioned in the proposal preamble, the estimated costs are only $55,000 per year for the entire category and an average annual cost of $6,800 per facility. More information regarding the standards for unregulated UFIP sources is available in the following document: *Unmeasurable Fugitive and Intermittent Particulate Emissions and Cost Impacts for Integrated Iron and Steel Facilities under 40 CFR part 63, subpart FFFFF,* which is available in the docket for this action.

After considering public comments and available information, pursuant to CAA sections 112(d)(2) and (3) and 112(h) and the *LEAN* court decision, we are promulgating the same MACT Floor standard as proposed.

3. What are the final MACT standards and how will compliance be demonstrated?

a. BF Unplanned Bleeder Valve Openings

In certain instances, as provided in CAA section 112(h), if it is the judgment of the Administrator that it is not feasible to prescribe or enforce an emission standard under CAA section 112(d)(2) and (3), the EPA may set work practice standards under CAA section 112(h) in lieu of numerical emission standards. For BF unplanned bleeder valve openings, the Administrator has determined that since there is no direct measurement of emissions, we are finalizing a work practice standard. We are finalizing an operational limit for two subcategories of blast furnaces: large furnaces with a working volume of equal to or greater than 2,500 m^3; and small furnaces with a working volume of less than 2,500 m^3. This is to account for variability in unplanned opening occurrences between furnace size due to design elements that allow higher operating pressure near the valve openings, which leads to less openings per year for large furnaces. For the large blast furnaces, we are finalizing an operational limit of four unplanned openings per rolling year per furnace. For small blast furnaces, we are finalizing an operational limit of 15 unplanned openings per rolling year per furnace. Both are based on a qualitative approach of using the highest number of unplanned openings from the top five performing furnaces (top four for large furnaces as there are only four operating large furnaces). For most MACT floor standards in NESHAP rules, we typically have actual emissions test data for each of the top five sources. To calculate the MACT floor limit we use all the data (all the runs) from all 5 sources to calculate the 99th UPL to account for variability. And, we conclude that this 99th value (which is higher than the true average) represents the average performance of the top 5 sources with an adjustment to account for variability.

With unplanned openings, we do not have a UPL type tool. So, as an alternative to a UPL, we considered all the data from the top five performers, and to ensure we account for variability among those top five performers, in this particular situation, we conclude that using the highest value (*i.e.,* highest number of unplanned openings) from any one source within the top five reflects our best estimate of an appropriate limit that would reflect performance of the top five sources with an adjustment to ensure we adequately account for the variability among those top five sources.

This approach is appropriate because it accounts for variability among the top five blast furnaces. For new sources, we are finalizing our proposed operational limit of zero unplanned openings per rolling year for both large and small furnaces because the best performing single source large and small blast furnace in our database reported zero unplanned openings for the most recent typical year.

Additionally, we are finalizing the work practice standards proposed for both furnace subcategories that require facilities to do the following: (1) install and operate devices (*e.g.,* stockline monitors) to continuously measure/monitor material levels in the furnace, at a minimum of three locations, using alarms to inform operators of static conditions that indicate a slip may occur, and alert them that there is a need to take action to prevent the slips and unplanned openings from occurring; (2) install and operate instruments such as a thermocouple and transducer on the furnace to monitor temperature and pressure to help determine when a slip may occur; (3) install a screen to remove fine particulates from raw materials to ensure only properly-sized raw materials are charged into the BF; and (4) develop, and submit to the EPA for approval, a plan that explains how the facility will implement these requirements. Additionally, facilities shall report the unplanned openings (including the date, time, duration, and any corrective actions taken) in their semiannual compliance reports.

b. BF Planned Bleeder Valve Openings

We are finalizing what we proposed for planned bleeder valve openings: a MACT floor limit of 8 percent opacity based on 6-minute averages. For new sources, we are finalizing an opacity of 0 percent. Facilities will have the flexibility to choose an appropriate approach to meet these opacity limits.

c. BF and BOPF Slag Processing, Handling, and Storage

As discussed above, we are finalizing an opacity limit of 10 percent based on 6-minute averages for BF and BOPF slag processing, handling, and storage, and slag pits. Regarding new sources, we are finalizing an opacity limit of 3 percent based on 6-minute averages for visible emissions from slag pits, and during slag handling, storage, and processing.

d. BF Bell Leaks

For bell leaks, we are finalizing a 20 percent opacity action level for large bell leaks as described below for new and existing large bells. This is not a numerical MACT emissions standard; because the Administrator has determined that it is not feasible to prescribe or enforce an emission standard in this instance, pursuant to CAA section 112(h), the EPA is setting work practice standards in lieu of numerical emission standards. We are also finalizing that the BF top must be observed monthly for visible emissions (VE) with EPA Method 22, 40 CFR part 60, appendix A–7, which determines the presence or absence of a visible plume, to identify leaks from the interbell relief valve (indicating leaks from the large bell). If VE are detected out of the interbell relief valve (indicating leaks from the large bell), the facility must perform EPA Method 9, 40 CFR part 60, appendix A–4, tests which determines the opacity (*i.e.,* degree to which a plume obscures the background) monthly, and if opacity is greater than 20 percent based on an average of three instantaneous and consecutive interbell relief valve openings, the facility must initiate operational or other corrective actions within five business days. After those five business days, the facility must perform EPA Method 9 tests again and, if opacity is greater than 20 percent, the facility will have another five business days to initiate further operational or corrective actions to reduce opacity to 20 percent or lower. After five additional business days (10 business days in total), the facility must perform EPA Method 9 tests again and, if opacity is still greater than 20 percent, the large bell seals must be repaired or replaced within four months. For the new and existing small bells, we are finalizing what we proposed, a requirement that facilities shall replace or repair seals prior to a metal throughput limit, specified by the facility, that has been proven and documented to produce no opacity from the small bells. Additionally, the facility must conduct monthly visible emissions testing for 15 minutes and amend the metal throughput limit in their operation and maintenance (O&M) plan as needed.

e. Beaching of Iron From BFs

As provided in CAA section 112(h), it is the judgment of the Administrator that it is not feasible to prescribe or enforce an emission standard for emissions from the beaching process, therefore the EPA is finalizing the proposed work practice standards in lieu of numerical emission standards. This work practice standard requires facilities to: (1) have full or partial enclosures for the beaching process or use CO_2 to suppress fumes; and (2) minimize the height, slope, and speed of beaching. This standard applies to both existing and new sources.

B. Reconsideration of BF Casthouse and BOPF Shop Standards for Currently Regulated Fugitive Sources Under CAA Section 112(d)(6) Technology Review

1. What did we propose for the BF casthouse and BOPF shop?

a. BF Casthouse

We proposed a 5 percent opacity limit based on 6-minute averages as an update to the CAA section 112(d)(6) technology review and proposed that facilities will need to measure opacity during the tapping operations (at least two times per month). We did not propose specific work practices for the BF casthouse, except that we proposed that the facilities will need to keep all openings, except roof monitors, closed during tapping and material transfer events (the only openings allowed during these events are those that were present in the original design of the casthouse).

b. BOPF Shop

Based on our review and analyses of the CAA section 114 information request responses we received in 2022 and 2023, and further review of the data the EPA assembled to support the 2020 RTR, we proposed that a standard composed of a 5 percent opacity limit with several specific work practices would be feasible and cost-effective for the BOPF shop. For example, based on the data we received, in the proposal we found that the maximum 3-minute opacity readings for the BOPF shops at four facilities were less than 5 percent. Furthermore, the use of work practices (described below) by the best performing facilities in the industry led us to conclude for the proposal that these work practices were feasible and, accordingly, we proposed a 5 percent opacity limit based on 3-minute average and work practices.

Specifically, we proposed that facilities will need to do the following: (1) keep all openings, except roof monitors (vents) and other openings that are part of the designed ventilation of the facility, closed during tapping and material transfer events (the only openings that would be allowed during these events are the roof vents and other openings or vents that are part of the designed ventilation of the facility) to allow for more representative opacity observations from a single opening; (2) have operators conduct regular inspections of BOPF shop structure for unintended openings and leaks; (3) optimize positioning of hot metal ladles with respect to hood face and furnace mouth; (4) monitor opacity twice per month from all openings, or from the one opening known to have the highest opacity, for a full steel cycle, which must include a tapping event; and (5) develop and operate according to an Operating Plan to minimize fugitives and detect openings and leaks. We proposed that the BOPF Shop Operating Plan shall include:

- An explanation regarding how the facility will address and implement the four specific work practices listed above;
- A maximum hot iron pour/charge rate (pounds/second) for the first 20 seconds of hot metal charge (*i.e.,* the process of adding hot iron from the BF into the basic oxygen process furnace);
- A description of operational conditions of the furnace and secondary emission capture system that must be met prior to hot metal charge, including:
- A minimum flowrate of the secondary emission capture system during hot metal charge;
- A minimum number of times, but at least once, the furnace should be rocked between scrap charge and hot metal charge;
- A maximum furnace tilt angle during hot metal charging: and;
- An outline of procedures to attempt to reduce slopping.

2. What comments did we receive on the proposed revised BF casthouse and BOPF shop standards, and what are our responses?

a. BF Casthouse

Comment: Commenters noted that the EPA did not apply UPL calculations to the opacity data, even though the EPA's practice has been to do so for other numerical standards established on limited data sets. Commenters claim that the EPA's proposed opacity limit of 5 percent, without any adjustment for variability, lacked justification or explanation and is therefore arbitrary and capricious. These commenters argued that, when utilizing limited datasets, it is appropriate for the EPA to account for variability, and there is no technical basis for suggesting that some statistical methods should not be applied to this data set. When the EPA set the 20 percent opacity limits in 2003, the preamble included the EPA's statistical basis supporting that the limits were achievable. Commenters also stated the EPA should also include a one-time alternative limit per furnace cycle similar to the new source standards in the 2003 NESHAP.

Response: The EPA disagrees with the specific approach of using UPL calculations to develop opacity limits in the same manner that the UPL is used to calculate emissions limits. The EPA has historically used the UPL approach to develop MACT limits for stack emissions of individual pollutants but has not historically determined opacity limits using a UPL approach. The UPL calculation introduces a predictive element to the statistics in order to account for variability. However, as noted by the commenter, unlike typical emissions testing, EPA Method 9 may result in values of zero, which cannot be used in the UPL calculation. While the EPA has used the UPL approach for floor determinations when setting MACT emissions limits, the proposed changes to the BOPF Shop and BF casthouse opacity standards were based on a proposed updating of the CAA section 112(d)(6) technology review. Additionally, in the case of opacity measured according to EPA Method 9, the data EPA reviewed to develop the proposed standards were the maximum 6-minute (or 3-minute as applicable) averages evaluated over the entire test period. Likewise, compliance determinations are also based on the same approach. Utilizing the maximum short-term average during each test period to determine an appropriate standard, and to determine compliance, inherently accounts for some variation in the data used to set the standard.

However, with regard to the comments on variability, we acknowledge that there are many opacity readings that occurred over the past 2 to 6 years at the Integrated Iron and Steel (II&S) manufacturing facilities that show that there is a substantial amount of variability in opacity measurements across time and across furnaces. For example, many opacity tests for BOPF and BF furnace cycles that were completed over these 2–6 years reported maximum 3-minute and 6-minute opacity readings below 5 percent for a substantial amount of the cycles. In fact, for many furnace cycles the maximum opacity was 0 percent. On the other hand, the data show that during some BOPF or BF cycles, opacity is above 5 percent and sometimes well above 20 percent. The EPA has additionally continued to receive opacity data and analyses since the close of the public comment period on this rulemaking.

The EPA was not able to adequately analyze all the available data before the deadline for this final rule ordered by the court in *California Communities Against Toxics.* Also, for most of the opacity tests that had maximum opacity readings above 5 and 10 percent, the EPA does not have any information that explains why the opacity readings were higher than 5 percent on those particular days. In most cases, the EPA is unable to determine the cause of the higher values based on the data and information currently available. Until further revision, the opacity limits in the NESHAP for existing BOPF Shops and existing BF casthouses will remain at 20 percent based on 3-minute averages for the BOPF Shop and 6-minute averages for the BF casthouse.

The opacity data and further explanation of the opacity data and related information can be found in the technical memo titled: *Unmeasured Fugitive and Intermittent Particulate Emissions and Cost Impacts for Integrated Iron and Steel Facilities under 40 CFR part 63, subpart FFFFF,* which is in docket for this final rule.

b. BOPF Shop

Comment: Some commenters conducted their own assessment of what measures would be needed to comply with the proposed opacity limit and work practice standards, which is of course facility-specific, because every BOPF shop is unique. Based on their assessments, these commenters asserted that each BOPF shop—after applying all ''required'' work practice standards and even other work practices that the EPA suggested—would likely need to install full-shop controls to meet a 5 percent opacity limit at all times. The commenters represented that the cost to apply this type of control would be high and would involve the addition of at least one large fabric filter device to properly capture fugitive emissions and allow for proper ventilation for the building. The commenters asked EPA to take into account the significant changes BOPF shops would have to make to meet a 5 percent opacity standard that even the best performers cannot currently achieve on a regular basis. They suggested that because of the exorbitantly and unreasonably expensive measures that would need to be undertaken by this industry sector, and the significant possibility that even facilities installing such measures would not be able to consistently meet the 5 percent opacity standard, the EPA should not move forward with the proposed opacity limit, at least until the Agency undertakes a robust engineering analysis to determine the technical and economic feasibility of controls that would be needed for BOPF shops to meet this lower standard.

Response: After considering public comments, the EPA now recognizes some operations may need to make more significant changes than we anticipated at proposal to meet the 5 percent opacity standard at all times. We acknowledge that there are many opacity readings that occurred over the past 2 to 6 years that indicate that there is a substantial amount of variability across time and across furnaces. For example, many opacity tests for BOPF cycles (*i.e.,* steel cycles) that were completed over these 2–6 years reported maximum 3-minute opacity readings below 5 percent for a substantial amount of the cycles. On the other hand, the data show that during some BOPF cycles, opacity is above 5 percent and sometimes above 20 percent.

The EPA was not able to adequately analyze all the available data before the court-ordered deadline for this final rule. Also, for those tests that had maximum opacity readings above 10 or 20 percent, in most cases, the EPA does not have any information that explains why the opacity readings were high on those particular days. In most cases, the EPA is unable to determine the cause of the higher values based on the data and information we have. Therefore, the EPA is not finalizing any changes to the opacity limits for the BOPF Shop in this final action. Instead, the EPA intends to continue reviewing and analyzing the opacity data from both the BF casthouse and the BOPF shop that we have and also collect additional data in the near future so that the EPA can gain a better understanding of the achievability of various opacity levels and the reasons why opacity levels are sometimes elevated. After EPA completes this additional data gathering and analyses, the EPA intends to consider potential revisions to the opacity limits in a separate future action. Until further revision, the opacity limit in the NESHAP for BOPF Shops will remain at 20 percent based on 3-minute averages, and the opacity limit in the NESHAP for BF casthouses will remain at 20 percent based on 6-minute averages, consistent with the current regulation.

The EPA is still finalizing opacity testing requirements for BF casthouse and BOPF shop fugitives as well as the proposed work practice standards for BOPF shop fugitives which are expected to reduce HAP emissions by 25 tpy. This accounts for 39% of the estimated emission reductions from UFIP sources with this promulgation.

Comment: One commenter stated that the EPA's reliance on the limited 2022 CAA section 114 testing results to determine that a 5 percent opacity standard would be achievable by BOPF shops for relatively modest capital and annual operating costs was inappropriate and has led the EPA to propose a standard that is technically and economically infeasible to meet. In an appendix to their comments, the commenters put forward alternative emission factors and cost estimates that, in their view, indicate the proposed standards would cost $88 million per ton to reduce just 2.6 tpy of HAP emissions industrywide. This conclusion is very different from the EPA's own analysis of its proposed rule, which was based on an assumption that no capital expenditures would be needed, and that for less than $500,000 per year industry-wide, all 11 existing BOPF shops should be able to meet a 5 percent opacity standard and comply with the numerous proposed work practice standards. Commenters also said that BOPF shops would not be able to meet a 5 percent opacity standard based on 3-minute averages from every opening at all times without significant capital expenditures, and remain concerned that even with this level of spending, there may be times when the shops would not be able to meet that standard. Commenters stated that until the EPA can demonstrate through a robust engineering study that the proposed opacity limit would be achievable at a certain spending level and with certain technology in place that is reasonable and cost-effective, the EPA should not move forward to finalize the proposed standards.

Response: As stated in previous responses to comments in this preamble, the EPA is not finalizing any changes to the opacity limits for the BOPF Shop in this final action. See previous responses to comments in this preamble for further explanation.

Comment: Commenters stated that because the proposal establishing an absolute 5 percent limit did not take into account the range of operations or impacts resulting in variability, it is clear that some periods of operation above 5 percent opacity will occur even with proper operation. They believe that any proposal that includes an opacity standard lower than 20 percent must provide that compliance is achieved provided there are no more than a set number of excursions above the revised limit in order to capture normal fluctuation events that occur during normal operation. Specifically, the EPA should follow the form of the current ''new source'' BOPF shop MACT opacity standard: maintain the opacity (for any set of 6-minute averages) of secondary emissions that exit any opening in the BOPF shop or other building housing a BOPF or shop operation at or below 15 percent, except that 6-minute averages greater than 15 percent but no more than 20 percent may occur twice per steel production cycle. A steel production cycle is defined in 40 CFR 63.7822.

Response: As stated in previous responses to comments in this preamble, the EPA is not finalizing any changes to the opacity limits for the BOPF Shop in this final action. The opacity limit for existing BOPF Shops will remain at 20 percent based on 3-minute averages. See previous responses to comments in this preamble for further explanation.

3. What are the revised standards for the BF casthouse and BOPF shop standards and how will compliance be demonstrated?

a. BF Casthouse

As stated in previous responses to comments in this preamble, the EPA is not finalizing any changes to the opacity limits for the BF casthouse in this final action. Facilities will need to comply with the 20 percent opacity limits that are already in the NESHAP. However, the EPA is requiring more frequent Method 9 tests as explained elsewhere in this preamble. See previous responses to comments in this preamble for further explanation.

b. BOPF Shop

For the reasons discussed in the responses to comments above, we are finalizing work practice standards for the BOPF. Specifically, in this final rule, we are requiring facilities to do the following: (1) keep all openings, except roof monitors (vents) and other openings that are part of the designed ventilation of the facility, closed during tapping and material transfer events (the only openings allowed during these events are the roof vents and other openings or vents that are part of the designed ventilation of the facility) to allow for more representative opacity observations from a single opening; (2) have operators conduct regular inspections of BOPF shop structure for unintended openings and leaks; (3) optimize positioning of hot metal ladles with respect to hood face and furnace mouth; (4) monitor opacity twice per month from all openings, or from the one opening known to have the highest opacity, for a full steel cycle, which must include a tapping event; and (5) develop and operate according to an Operating Plan to minimize fugitives and detect openings and leaks.

The purpose of the Operating Plan is to address variability in unit design and operations by creating an individualized strategy for implementing work practice standards at each source. Owners and operators can develop specific work practices that make sense for each unit and that maximize emission reduction efficiency for each unit. We require that the BOPF Shop Operating Plan include:

- An explanation regarding how the facility will address and implement the four specific work practices listed above;
- A maximum hot iron pour/charge rate (pounds/second) for the first 20 seconds of hot metal charge (*i.e.,* the process of adding hot iron from the BF into the basic oxygen process furnace);
- A description of operational conditions of the furnace and secondary emission capture system that must be met prior to hot metal charge, including:
- A minimum flowrate of the secondary emission capture system during hot metal charge;
- A minimum number of times, but at least once, the furnace should be rocked between scrap charge and hot metal charge;
- A maximum furnace tilt angle during hot metal charging: and;
- An outline of procedures to attempt to reduce slopping.

The BOPF shop work practice standards and Operating Plan are expected to result in the same HAP emission reductions as the Proposed Rule at 25 tpy. This accounts for 39% of the estimated emission reductions from UFIP sources with this promulgation.

C. What are the decisions for fenceline monitoring?

1. What did we propose for fenceline monitoring?

Pursuant to CAA section 112(d)(6), we proposed adding fenceline monitoring for chromium. Fenceline monitoring refers to the placement of monitors along the perimeter of a facility to measure pollutant concentrations. Coupled with requirements for root cause analysis and corrective action upon triggering an actionable level, this work practice standard is a development in practices considered under CAA section 112(d)(6) for the purposes of managing fugitive emissions. The measurement of these pollutant concentrations and comparison to concentrations estimated from mass emissions via dispersion modeling can be used to ground-truth emission estimates from a facility's emissions inventory. If concentrations at the fenceline are greater than expected, the likely cause is that there are underreported or unknown emission sources affecting the monitors. In addition to the direct indication that emissions may be higher than inventories would suggest, fenceline monitoring provides information on the location of potential emissions sources. Further, when used with a mitigation strategy, such as root cause analysis and corrective action upon exceedance of an action level, fenceline monitoring can be effective in reducing emissions and reducing the uncertainty associated with emissions estimation and characterization. Finally, public reporting of fenceline monitoring data provides public transparency and greater visibility, leading to more focus and effort in reducing emissions.

Specifically, we proposed that facilities must install four ambient air monitors at or near the fenceline at appropriate locations around the perimeter of the facility, regardless of facility size, based on a site-specific plan approved by the EPA to collect and analyze samples for total chromium every sixth day. In addition, we proposed that facilities must implement the following work practice requirement: if an installed fenceline monitor has a 12-month rolling average delta c concentration—calculated as the annual average of the highest sample value for a given sample period minus the lowest sample value measured during that sample period—above the proposed action level of 0.1 μg/m^3 for total chromium, the facility must conduct a root cause analysis and take corrective action to prevent additional exceedances. Data would be reported electronically to the EPA's Compliance and Emissions Data Reporting Interface (CEDRI) on a quarterly basis and subsequently available to the public via the Web Factor Information Retrieval system (WebFIRE) website. Furthermore, we proposed a sunset provision whereby if the annual average delta c remain 50-percent or more below the action level (*i.e.,* 0.05 μg/m^3 or lower) for a 24-month period, then the facility can request to terminate the fenceline monitoring. Termination of the fenceline monitoring in no way impacts the requirement for facilities to meet all other obligations under this subpart including the general duty to minimize emissions of 40 CFR 63.7810(d).

Because a method has not yet been proposed or promulgated for fenceline monitoring of metals, we proposed that fenceline monitoring would begin no later than one year after the EPA's promulgation of a fenceline test method, or two years after the promulgation of the final rule, whichever is later. The EPA is working as expeditiously as possible to propose a new metals fenceline method. As part of the prior CAA section 114 information collection effort, we relied on a common ambient monitoring method [2] for the collection of the metals samples and associated analytical method [3] for multi-metals for the analysis. While these methods are robust and appropriate for ambient trends applications, EPA needs to further investigate and revise these approaches for a stationary source regulatory program to ensure improved precision and accuracy in the method, in the same manner EPA developed Method 327 [4] from TO–15 in the recent Synthetic Organic Chemical Manufacturing Industry: Organic National Emission Standards for Hazardous Air Pollutants (NESHAP)—40 CFR 63 Subparts F,G,H,I proposed rule, published on April 25, 2023 (88 FR 25080). The required determinations of whether the action level has been exceeded and any subsequent root cause investigation will begin once the first annual rolling average is acquired.

2. What comments did we receive on the monitoring requirements, and what are our responses?

Comment: Commenters stated that the proposed focus on chromium as a ''surrogate'' and the proposal to set an action level for only chromium is demonstrably inadequate. Emission standards under CAA section 112(d) must be ''comprehensive controls for each source category that must include limits on each hazardous air pollutant the category emits.'' (*LEAN,* 955 F.3d at 1095–96.) As identified in several background documents for this proposed rule, air pollutants from various facility processes include multiple toxic metals in addition to chromium including arsenic, mercury, and lead; toxic halogenated compounds including carbonyl sulfide, carbon disulfide, hydrogen chloride, hydrogen fluoride, D/F; and other toxic pollutants such as hydrocarbons and PM. The CAA requires ''as many limits as needed to control all the emitted air toxics of a

---

[2] Reference Method for the Determination of Suspended Particulates in the Atmosphere (High Volume Method), 40 CFR 50, Appendix B.

[3] Method IO–3, Determination of Metals in Ambient Particulate Matter Using Inductively Coupled Plasma (ICP) Spectroscopy.

[4] **Federal Register** Notice published on April 25, 2023 (88 FR 25080).

particular source category.'' (*Id.* at 1097.) Commenters stated that the 2023 Proposal is unlawful on its face for only requiring monitoring and action level standards for chromium.

Response: The EPA disagrees that conducting fenceline monitoring for only chromium is inadequate or unlawful. The EPA recognizes there are multiple toxic metals emitted by various facility processes from the iron and steel facilities. We reiterate that we did not intend to measure all pollutants, especially pollutants that are emitted from point sources that are directly measurable through source tests and continuous monitoring systems. These emissions sources and pollutants are subject to other standards under these MACT. We disagree that it is necessary to conduct fenceline monitoring for every HAP emitted from fugitive emission sources at integrated iron and steel facilities. Integrated iron and steel emissions can contain many different HAP and it is very difficult for any fenceline method to detect every HAP potentially emitted from integrated iron and steel facilities. The fenceline monitoring standard was proposed as part of the CAA section 112(d)(6) technology review to improve management of fugitive emissions of metal HAPs and not as a risk reduction measure. In order to meet that goal of improved management of fugitive emissions, it is not necessary to obtain an accurate picture of the level of all HAP emitted. We chose to propose fenceline measurements only for chromium because it was a risk driver in the 2020 RTR analyses and has been determined to be a good surrogate for other HAP metals, especially arsenic, which was the other HAP metal driving the risks in the 2020 RTR risk analyses. Additionally, at the fenceline, based on fenceline monitoring conducted in 2022–23 at Integrated Iron and Steel facilities in response to the section 114 request, the highest monitored lead levels were found to be 5 times lower than the current air quality health NAAQS value (last issued in 2015 to provide an ''adequate margin of safety to protect public health''). However, based on a lack of information on fugitive lead and other metal HAP emissions, the EPA does agree with this commenter that there is a need for more data gathering, both at the fenceline and from other sources on the facilities. EPA did not propose nor are we prepared to promulgate a requirement to monitor any metals other than chromium as part of the fenceline requirement, but we intend to gather more fenceline monitoring data for lead in 2024 at Integrated Iron and Steel facilities to better characterize fugitive lead emissions. Additionally, we intend to gather more data regarding HAP metals from sinter plant stacks through the use of PM continuous monitoring systems (PM CEMs). We intend to collect this data in a separate action under CAA section 114 that will follow this final rule.

Comment: Commenters stated that the EPA should require monitoring and set action level standards for all HAP metals emitted by II&S facilities. These commenters asserted that the incremental cost to monitor for all metals is insignificant and would have outsized benefits to the community by establishing multiple triggers for assessment and corrective action. As an alternative to required fenceline monitoring for all HAP metals, commenters stated the EPA should consider implementing a fenceline standard for lead because most communities surrounding II&S facilities are EJ communities exposed to lead from multiple sources. Commenters also specifically supported a fenceline monitoring requirement for arsenic.

Response: The EPA observes that it is technically feasible to require further speciation of metal HAPs collected within a single sample. Although increasing the analyte list does increase the analytical costs because additional calibration standards are required, the EPA agrees with commenters that the costs to monitor for additional metals would be relatively low. However, the incremental cost of monitoring for additional HAPs is not the only consideration in determining the scope of a fenceline monitoring requirement for this source category. The EPA must also consider the efficacy of instituting a fenceline monitoring requirement for additional HAPs, as well as practical implementation concerns. At this time, the EPA believes these factors weigh in favor of requiring fenceline monitoring for chromium while continuing to gather information on other metal HAPs.

As discussed above, the EPA previously determined in the 2020 RTR that chromium is one of the two principal drivers of health risk in this source category and is also an effective surrogate for arsenic, which is the other most significant contributor to risk. Because the principal purpose of fenceline monitoring in this source category is to assure compliance with the emission standards that address fugitive emissions of particulate HAP metals, implementing this development will provide ''necessary'' protection against fugitive emissions of metal HAPs (including those that pose greatest risks to public health). Fenceline monitoring is a development in practices, for the purpose of managing fugitive emissions. In sum, fenceline monitors will be placed at or near the perimeter of the applicable facility to measure pollutant concentrations; this measurement is coupled with the requirement to conduct applicable root cause analyses and implement corrective action upon triggering an actionable level. The utilization of fenceline monitors will serve to manage fugitive emissions with the intent to reduce emissions, as well as to reduce uncertainty associated with initial emissions estimation. The use of fenceline monitors, coupled with action levels, represents a development in work practices. Therefore, focusing fenceline monitoring requirements on chromium is appropriate as a development pursuant to CAA section 112(d)(6). Requiring fenceline monitoring for chromium alone also facilitates establishing an appropriate action level, reduces analytical costs, and simplifies the determination of compliance for integrated iron and steel owners and operators.

By contrast, including additional metal HAPs in the fenceline monitoring program would require the EPA to resolve a number of technical issues, including how an action level for additional HAPs would be set, and whether each metal HAP would have its own action level or instead a single action level for the sum of metal HAP measured. The EPA was not able to develop the information needed to address these issues within the timeframe for this rulemaking. Given that the available information indicates that HAP metals emitted from the integrated iron and steel facilities other than chromium and arsenic do not contribute to significant ambient concentrations at or near the facility boundaries (*e.g.,* fenceline) at these facilities, we have determined that at present the benefits of including other metal HAPs in the scope of the fenceline monitoring requirement are also unclear.

Although we did not propose nor are we prepared to promulgate a fenceline monitoring requirement for any metals other than chromium at this time, the EPA recognizes that further information on fugitive emissions of lead and other HAP metals would be useful in informing whether and how a fenceline monitoring requirement for additional HAP metals as part of a future rulemaking. Accordingly, we intend to gather more data to better characterize fugitive lead and other HAP metals through a separate action that will follow this final rule as described in the previous response in this preamble.

Comment: Commenters stated that the EPA should not set an action level that would be triggered if the UFIP sources were meeting all of the proposed opacity limits and work practice standards, which is the EPA's stated purpose for establishing the fenceline monitoring program. Because the EPA did not consider or analyze whether II&S facilities could maintain UFIP emissions at rates to ensure that the action level would not be triggered or how much it would cost to maintain emissions below the action level, the EPA should not entertain these lower values of 0.08 and 0.09 µg/m³. Commenters stated that for the EPA to do so would be arbitrary and capricious per se.

Response: The EPA acknowledges the support and is finalizing the action level at 0.1 µg/m³ as proposed.

Comment: Commenters stated that regardless of the numeric value selected for the action level, the EPA should express the chromium action level in µg/m³ to at least two decimal places and clarify that rounding occurs to the second decimal place (*e.g.,* 0.11 µg/m³ would not round down to 0.10 µg/m³ and would therefore exceed the action level). The EPA states that ''[b]ecause of the variability and limitations in the data, to establish the proposed action level we rounded[. . .]to one significant figure (*i.e.,* 0.1 µg/m³).'' Commenters stated that there are two issues with this statement: (1) significant figures do not completely characterize numerical precision, and (2) reporting chromium concentrations in µg/m³ to one decimal place does not reflect the precision of modern sampling and analytical techniques. Commenters stated that in response to the first point, consider two hypothetical reported chromium concentrations: 0.1 µg/m³ and 0.01 µg/m³. Both have only one significant digit, but the second concentration is reported with a greater level of precision. As for the second point, Table 1 in EPA Compendium Method IO–3.5, which was the analytical method used to determine fenceline chromium concentrations as part of the EPA's CAA section 114 ICR, lists the estimated method detection limit for chromium as 0.01 ng/m³ (0.00001 µg/m³). This low method detection limit demonstrates the sensitivity and precision of modern sampling and analytical methods. As such, chromium concentrations measured with these methods should be reported to at least two decimal places (assuming units of µg/m³).

Response: The EPA disagrees with the commenter that more than one decimal place should be used for the action level and further disagrees with their definition of precision. Measurement precision relates to the degree of variation in repeated measurements, and not what decimal place a reading is. In the example proposed, 0.1 µg/m³ and 0.01 µg/m³, these are merely two values of differing magnitude, and not two values of different precision.

The EPA also disagrees that the detection limit of EPA Compendium Method IO–3.5 has meaning in this context. The detection limit is the lowest level at which a valid measurement can be collected, beyond indicating that, in this case, the measured values are within the measurable range, it has no practical impact upon the number of significant digits appropriate.

While the analytical techniques may be able to determine the concentration out to more than one significant figure, the setting of the action level is based not just upon the measurement itself, but upon projected gains under the newly required limits on UFIP and the calculation of delta c, further complicating the determination of an appropriate action level. The EPA is finalizing the action level at one significant figure as proposed.

Comment: Commenters stated that even if the EPA can sufficiently explain why an action level was set for chromium for II&S facilities based on fenceline monitoring, the EPA should set the action level below 0.1 µg/m³ because fenceline data collected as part of EPA's CAA section 114 collection request shows that a lower action level is achievable. Because the EPA did not request that all eight II&S facilities perform fenceline monitoring pursuant to the CAA section 114 request, the EPA did not identify the top five best performing facilities. However, two of the four facilities that conducted fenceline monitoring (Cleveland Works and Burns Harbor) had 6-month chromium delta c averages below 0.08 µg/m³, and a third facility (Granite City) is projected to be at 0.09 µg/m³ after implementing provisions of the rulemaking. The EPA has failed to explain why they are requiring an action level that constitutes the lowest number (0.1 µg/m³) instead of the level that three of the four facilities that conducted fenceline monitoring are able to meet (0.10 µg/m³). Accordingly, the EPA should set the action level below 0.1 µg/m³.

Response: Consistent with refineries and all other proposed fenceline monitoring standards, we are implementing the action level as a single significant digit as discussed further in the response to the previous comment of this section.

3. What are the revised standards for the fenceline monitoring requirements and how will compliance be demonstrated?

We are finalizing what we proposed: facilities must install four ambient air monitors at or near the fenceline at appropriate locations around the perimeter of the facility based on a site-specific plan that must be submitted to and approved by the EPA, regardless of facility size. These monitors shall collect and analyze samples for total chromium every sixth day. The facilities must also implement the following work practice requirement: if an installed fenceline monitor has a 12-month rolling average delta c concentration that is above the action level of 0.1 µg/m³ for total chromium, calculated as the annual average of the delta c determined during each sample period over the year (highest sample value for a given sample period minus the lowest sample value measured during that sample period), the facility must conduct a root cause analysis and take corrective action to prevent additional exceedances.

A facility may request to terminate fenceline monitoring after 24 months of consecutive results 50 percent or more below the action level. The EPA selected the monitoring locations and sampling frequency as specified to maintain the same basis of monitoring as that used in the derivation of the action level as discussed in the preamble to the proposed rule (88 FR 49414). The use of four monitors was selected and not expanded to the same number of monitoring sites as EPA Method 325A because, unlike EPA Method 325A that uses passive samplers, the methodology used for both the CAA section 114 request and the potential candidate method for this rule requires power at each sampling location, dramatically increasing the potential cost of each monitoring site. The sampling frequency of every six days was selected to both mimic that of the CAA section 114 request as well as to ensure operations on each day of the week would be represented in the calculation of the annual average delta c. Data will be reported electronically to CEDRI on a quarterly basis and subsequently available to the public via the WebFIRE website.

In response to many comments regarding fugitive emissions of lead and other metals, we recognize the need to gather more data to characterize these fugitive emissions at the fenceline and sinter plants. We intend to take a separate action on this data collection for lead and potentially other metals action under CAA section 114.

D. Standards To Address Unregulated Point Sources for Both New and Existing Sources

1. What standards did we propose to address unregulated point sources?

In addition to the unregulated UFIP sources, we identified five unregulated HAP from sinter plant point sources (CS_2, COS, HCl, HF, and Hg); three unregulated HAP from BF stove and BOPF point sources (D/F, HCl and THC (as a surrogate for organic HAP other than D/F)); and two unregulated HAP from BF point sources (HCl and THC (as a surrogate for organic HAP other than D/F). The proposed MACT emission limits for these unregulated point sources are in Table 3.

TABLE 3—ESTIMATED HAP EMISSIONS AND PROPOSED MACT LIMITS FOR POINT SOURCES

Process	HAP	Estimated source category emissions	Proposed MACT limit
Sinter Plants	CS_2	42 tpy	Existing and new sources: 0.028 lb/ton sinter.
Sinter Plants	COS	57 tpy	Existing sources: 0.064 lb/ton sinter. New sources: 0.030 lb/ton sinter.
Sinter Plants	HCl	11 tpy	Existing sources: 0.025 lb/ton sinter. New sources: 0.0012 lb/ton sinter.
Sinter Plants	HF	1.2 tpy	Existing and new sources: 0.0011 lb/ton sinter.
Sinter Plants	Hg	66 pounds/yr	Existing sources: 3.5e–5 lb/ton sinter. New sources: 1.2e–5 lb/ton sinter.
BF casthouse control devices.	HCl	1.4 tpy	Existing sources: 0.0013 lb/ton iron. New sources: 5.9e–4 lb/ton iron.
BF casthouse control devices.	THC	270 tpy	Existing sources: 0.092 lb/ton iron. New sources: 0.035 lb/ton iron.
BOPF	D/F (TEQ[1])	3.6 grams/yr	Existing and new sources: 4.7e–8 lb/ton steel.
BOPF	HCl	200 tpy	Existing sources: 0.078 lb/ton steel. New sources: 1.9e–4 lb/ton steel.
BOPF	THC	13 tpy	Existing sources: 0.04 lb/ton steel. New sources: 0.0017 lb/ton steel.
BF Stove	D/F (TEQ)	0.076 grams/year	Existing and new sources: 3.8e–10 lb/ton iron.
BF Stove	HCl	4.5 tpy	Existing sources: 5.2e–4 lb/ton iron. New sources: 1.4e–4 lb/ton iron.
BF Stove	THC	200 tpy	Existing sources: 0.1 lb/ton iron. New sources: 0.0011 lb/ton iron.

[1] Toxic equivalency.

2. What comments did we receive on the unregulated point sources, and what are our responses?

Comment: Commenters state that they submitted additional stack tests in Appendix L that cover the EPA's proposed MACT standards for BF Stoves, BF Casthouses, and BOPF Primary Control Devices. These commenters do not represent that the additional data submitted in Appendix L alone or in combination with data underlying the EPA's proposed standards capture the full range of operating conditions for these point sources; however, they believe these additional data further indicate that the EPA's limited datasets do not sufficiently account for variability and, therefore, are not representative of best performing units in this source category. The same commenters state that the EPA's 15 proposed HAP limits for new sources rely on insufficient data and are unlikely to be technologically feasible. They are also concerned that any new sources would also not be able to meet the emission rates of the best performers given the lack of sufficient data underlying the EPA's proposed new source limits for the 15 HAPs that inherently do not capture process, operational, raw material, or seasonal and measurement variability of the EPA-designated best performing source. Achievability of the new source proposed limits is a concern because it is also unlikely that it would be technologically feasible for pollution control equipment to guarantee any degree of control of such low or dilute concentrations of D/F, PAHs, COS, CS_2, Hg, THC, HF, and HCl, which fall below the lowest target concentrations and capture limitations of such equipment. Further, the sources of raw materials and their impact on emissions variability cannot be reasonably predicted.

Response: The EPA has considered these additional data and, where deemed valid, incorporated the data into updated UPL calculations for the point sources and HAPs. The promulgated limits are based on MACT floor calculations (UPL) using the available valid data, which represents our best estimate of current average performance, accounting for variability (*i.e.,* UPL calculations), of the sources for which we have valid data (for affected sources). Additionally, based on industry comments, we: (1) used surrogate limits for some HAP; (2) changed the format of some limits; and (3) established work practices for HAP where majority of data were below detection.

Furthermore, based on the limited data we have, we estimate that all facilities will be able to meet these limits without the need for new add-on control devices (*e.g.,* we have no data indicating a source cannot currently comply with these limits). Nevertheless, we acknowledge that there are uncertainties because of the limited data. However, pursuant to section 112 of the CAA and the LEAN court decision, we must promulgate MACT emissions limits based on available data in order to fulfill our court ordered CAA section 112(d)(6) obligations.

Comment: Commenters stated that if EPA nonetheless proceeds with BF Stove limits, the form must be revised to lb/MMBtu, and that EPA erroneously used iron, rather than steel, production rates. The commenter said the agency should use contemporaneous iron production rates instead, which were provided on May 25, 2023. Notwithstanding these errors, emission limits for combustion units including BF stoves would be most appropriately expressed as lb/MMBtu, as although stove and blast furnace operations are interrelated, there are significant site specific differences in operation which make blast furnace production inappropriate to use when developing a limit for BF stoves. Lb/MMBtu would be more appropriate because the emissions per amount of heat released is more directly related to total quantity of emissions generated. Further, gas flow can be directly measured to account for varying BF stove operation. Iron production is intermittent with tapping and plugging of the furnace, so using emissions per ton could produce misleading results and should not be used.

Response: The EPA agrees that BF stove emission limits in the units of lb/MMBtu would be more appropriate than unis of lb/ton. We have recalculated UPLs for BF stove emissions in the units of lb/MMBtu and are finalizing MACT floor limits for HCl and THC emissions from BF stoves in the units of lb/MMBtu. No additional costs are expected to meet these limits.

Comment: Commentors stated that the EPA should not finalize its proposed D/F limit for BF Stoves because D/F is not present, or, if present, is only in trace amounts. The EPA estimates that the 17 BF Stoves in the source category collectively emit 0.076 grams per year of D/F. Commentors said that basing the proposed D/F limit on only two tests, with a total of only 6 data points (5 of which are BDL) is not permissible. If the EPA nevertheless pursues D/F limits for BF Stoves, the EPA should review and revise the limits to ones that are representative of the emissions limitations being achieved by the best performers. The EPA should consider work practices, such as good combustion practices, in lieu of numerical limits.

Response: Pursuant to the LEAN decision, CAA section 112(d)(2)/(3) and the court order for the EPA to complete this final rule pursuant to CAA section 112(d)(6) by March 11, 2024, the EPA must establish standards for previously unregulated HAP based on available data in this final rule. The EPA collected emissions test data through the CAA section 114 requests. For D/F from BF stoves, when we made a determination of BDL according to the procedures outlined in Determination of ‘‘non-detect’’ from EPA Method 29 (multi-metals) and EPA Method 23 (dioxin/furan) test data when evaluating the setting of MACT floors versus work practice standards (Johnson 2014) (Johnson memo) available in the docket (EPA–HQ–OAR–2002–0083–1082), two of the six runs are determined to be non-detect. Though we disagree in the number of non-detect values with the commenter, we agree that, as only 33 percent of test runs were detected values, a work practice under CAA section 112(h) is appropriate for the control of D/F from BF Stoves. The EPA generally considers a work practice to be justified if a significant majority of emissions data available indicate that emissions are so low that they cannot be reliably measured (*e.g.,* more than 55 percent of test runs are non-detect) as discussed in the Johnson Memo. An appropriate work practice for D/F for the stoves, due to their similarity in operation with boilers and other heaters, is good combustion practices, represented for this source by the THC standard being finalized in this rule. The numerical THC standard provides assurance of good combustion practices, and a further tune-up style work practice requirement is not necessary.

Comment: Commentors stated that the EPA should not finalize its proposed CS_2 and HF limits for sinter/recycling plants because the available data demonstrates these pollutants are not emitted. The EPA estimates sinter/recycling plants emit: a total 1.3 tpy of HF and 23 tpy of CS_2 for the source category. The EPA bases its CS_2 estimate on a limited data set of six test runs where the EPA flagged 83 percent (5 out of 6) of those results as below detection limit (BDL). (2023 Data Memo at app. A) BDL means that emissions are so low they are not able to be accurately read, measured, or quantified. Similarly, 13 out of 14 (93 percent) of test runs for HF from sinter/recycling plants were flagged BDL by the EPA, indicating that HF is not emitted or emitted in trace amounts, and thus EPA should not set a numerical standard for HF for sinter/recycling plants. The commentor stated if the EPA nevertheless proceeds with such numerical limits, it must revise its proposed limits upwards to help to account for known data variability and limited datasets. Commentors stated that data underlying the EPA's proposed CS_2 and HF limits includes a significant number of readings below the detection limit. The EPA explains that ‘‘greater than 50 percent of the data runs were BDL’’ for HF and CS_2 from sinter/recycling plants. (2023 MACT Costs Memo at 19–21, tbl. 24.) The proposed limits for HF and CS_2 are not representative of current performance due to the frequency of near or BDL. The EPA has noted that ‘‘section 112(d)(2) of the CAA specifically allows EPA to establish MACT standards based on emission controls that rely on pollution prevention techniques.’’ Where a majority of BDL values exist, the EPA should instead consider pollution control techniques, such as a work practice, rather than individual limits for these HAPs. Thus, the EPA should rely on the oil-content and VOC limit pollution control techniques that are already in place for these pollutants.

Response: Pursuant to the LEAN decision, CAA section 112(d)(2)/(3) and the court's Order for EPA to complete this final rule pursuant to CAA section 112(d)(6) by March 11, 2024, the EPA must establish standards for previously unregulated HAP based on available data in this final rule. The EPA reviewed the data in question and agrees with the commenter's assessment of the number of non-detect results for CS_2 and HF. Further, the single test run for which HF was detected was only slightly above the detection limit (0.09 ppmv detected value versus the detection limit of 0.08 ppmv). The EPA generally considers a work practice to be justified if a significant majority of emissions data available indicate that emissions are so low that they cannot be reliably measured (*e.g.,* more than 55 percent of test runs are non-detect) as discussed in the Johnson Memo. Due to the extremely high percentage of non-detect values, 83 and 93 percent for CS_2 and HF respectively, it is appropriate for both of these compounds at the sinter plant to be represented by a work practice standard according to CAA section 112(h). For CS_2, the work practice being finalized consists of the existing requirement to control the oil content in the sinter or the VOC emissions at the windbox exhaust (40 CFR 63.7790(d)) to control the source of the sulfur, combined with the new numerical standard for COS being finalized in this rulemaking. For HF, where 93 percent of the values were below the detection limit and the only detected value is only slightly above, the numerical standard for HCl being finalized in this rule shall act as a work practice (or surrogate) for HF, as control of HCL will also control HF.

3. What are the revised standards for the unregulated point sources and how will compliance be demonstrated?

We are finalizing the MACT Floor emission limits mostly as we proposed, but with minor adjustments for some limits based on the inclusion of additional valid data in the UPL calculations, the revision of the format of BF Stove emission limits as advised in the comments received, and the incorporation of work practices and surrogates for CS_2 and HF at sinter plants and D/F from the BF Stove. These work practices are being finalized because under CAA section 112(h), the Administrator has determined that it is not feasible to prescribe or enforce an emissions standard for these unregulated point sources. Furthermore, based on consideration of public comments and further analyses, for mercury emissions from existing sinter plants, we are promulgating a BTF limit based on installation and operation of activated carbon injection (ACI), described in section III.E of this preamble. The emission limits, along with estimated annual emissions, for the unregulated point sources for the final rule are provided in Table 4.

TABLE 4—HAP EMISSIONS AND FINAL MACT LIMITS FOR PREVIOUSLY UNREGULATED POINT SOURCES

Process	HAP	Estimated source category emissions	Promulgated MACT emissions limit (or other applicable standard as noted below)
Sinter Plants	CS_2	23 tpy	Meet applicable COS limit and meet requirements of 40 CFR 63.7790(d).
Sinter Plants	COS	72 tpy	Existing sources: 0.064 lb/ton sinter. New sources: 0.030 lb/ton sinter.
Sinter Plants	HCl	12 tpy	Existing sources: 0.025 lb/ton sinter. New sources: 0.0012 lb/ton sinter.
Sinter Plants	HF	1.3 tpy	Meet the applicable HCl standard.
Sinter Plants	Hg	55 pounds/yr	Existing sources: 1.8e–5 lb/ton sinter.[2] New sources: 1.2e–5 lb/ton sinter.
BF casthouse control devices.	HCl	1.4 tpy	Existing sources: 0.0056 lb/ton iron. New sources: 5.9e–4 lb/ton iron.
BF casthouse control devices.	THC	270 tpy	Existing sources: 0.48 lb/ton iron. New sources: 0.035 lb/ton iron.
BOPF	D/F (TEQ[1])	3.6 grams/yr	Existing and new sources: 9.2e–10 lb/ton steel.
BOPF	HCl	200 tpy	Existing sources: 0.058 lb/ton steel. New sources: 2.8e–4 lb/ton steel.
BOPF	THC	13 tpy	Existing sources: 0.04 lb/ton steel. New sources: 0.0017 lb/ton steel.
BF Stove	D/F (TEQ)	0.076 grams/year	Good combustion practices demonstrated by meeting the THC limit.
BF Stove	HCl	4.5 tpy	Existing sources: 0.0012 lb/MMBtu. New sources: 4.2e–4 lb/MMBtu.
BF Stove	THC	200 tpy	Existing sources: 0.12 lb/MMBtu. New sources: 0.0054 lb/MMBtu.

[1] Toxic equivalency.

[2] See section III.E for description of the final mercury limit.

E. Reconsideration of Standards for D/F and PAH for Sinter Plants Under CAA Section 112(d)(6) Technology Review, and Beyond-the-Floor Limit for Mercury

1. What standards did we propose to address the reconsideration of the D/F and PAH standards for sinter plants, and new mercury limits from sinter plants?

We proposed emissions limits of 3.5E–08 lbs/ton of sinter for D/F toxic equivalency (TEQ) and 5.9E–03 lbs/ton of sinter for PAHs for existing sinter plant windboxes. These limits reflect the average current performance of the four existing sinter plants for D/F and PAHs pursuant to CAA section 112(d)(6). For mercury, we proposed a MACT Floor limit of 3.5E–05 lbs/ton sinter for existing sources, as described in section III.D of this preamble.

For new sources, we proposed emissions limits of 3.1E–09 lbs/ton of sinter for D/F (TEQ), and 1.5E–03 lbs/ton of sinter for PAHs for new sinter plant windboxes that reflect the current performance of the one best performing sinter plant pursuant to CAA section 112(d)(6). Regarding mercury, we proposed a MACT floor limit of 1.2E–05 lbs/ton sinter for new sinter plants.

2. What comments did we receive on the reconsideration of the D/F and PAH standards for sinter plants, and mercury emissions, and what are our responses?

Comment: Commenters stated that the Agency's review of ACI during the 2020 RTR found that the ACI add-on control technology for sinter/recycling plant windboxes would not be cost-effective. They said the Agency's BTF analysis and evaluation of ACI as a potential control option for sinter/recycling plants are flawed. Commenters said that they are unaware of any application of ACI with a wet scrubber for particulate control being sufficiently demonstrated in practice as a control technology for D/F. Commenters also assert that the assumed brominated powdered activated carbon (PAC) injection rate of 1.7 lb/MMacf based on 2012 test data from the Gerdau Sayreville, NJ electric arc furnace baghouse is unproven in the II&S industry and that the Agency may be underestimating the required injection rates.

Response: Based on our review of the available information and analyses, we estimate the brominated powdered activated carbon (PAC) can achieve 85 percent reduction of D/F when used with fabric filters. Regarding wet scrubbers, based on a scientific article by H.Ruegg and A. Sigg (See ''Dioxin Removal In a Wet Scrubber and Dry Particulate Removal'', Chemosphere, Vol. 25, No. 1–2, p. 143–148), we estimate ACI used with a wet scrubber will achieve 70 percent reduction. Given that PAHs and dioxins are both semi-volatile organic compounds, we assume the ACI with a wet scrubber will also achieve 70 percent reduction of PAHs from sinter plants with a wet scrubber. We note that only one of the 4 sinter plants is controlled with a wet venturi scrubber. The other three have baghouses.

Comment: Commenters stated the EPA's MACT limits for existing sinter plants should be lower, arguing that the EPA's establishment of separate MACT floors for COS, HCl, and mercury for new plants at less than half of the limit for existing sources indicates how outdated the 50 plus year-old existing sinter plants are. Commenters argued that the fact that only two integrated steel mills continue to operate sinter plants, down from nine facilities twenty years ago, further suggests that American sinter technology is outdated. In commenters' view, the EPA should not give these outdated sinter plants a ''pass'' on reducing their significant emissions of hazardous air pollutants.

Commenters further stated that the EPA should reconsider rejecting ACI as too expensive, arguing that steel mills can clearly afford this control measure based on recent profit margins. The EPA should more carefully consider an evaluation of the human health costs associated with the HAP emissions and factor that into the Agency's cost estimate. Alternatively, the commenters urged EPA to consider advanced or additional pollution controls on sinter windboxes, the most significant source of emissions from sinter plants. The proposed NESHAP does not appear to have considered the use of wet electrostatic precipitators, redundant baghouses, or other types of controls.

Response: To address the comments that sinter plants need more controls to reduce emissions of hazardous pollutants, specifically the addition of ACI controls, we are finalizing emissions limits pursuant to CAA section 112(d)(6) for D/F and PAHs, and CAA section 112(d)(2)/(3) BTF limits for mercury that reflect the installation and operation of ACI controls. We conclude that the estimated costs for these ACI controls (described below) are reasonable given that these controls will achieve significant reductions of these three HAPs, which are persistent, bioaccumulative and toxic (PBT) HAPs. For example, D/F are highly toxic carcinogens that bioaccumulate in various food sources such as beef and dairy products. Mercury, once it is converted to methylmercury in aquatic ecosystems, is also known to bioaccumulate in some food sources, especially fish and marine mammals which are consumed by people, especially people who rely on subsistence fishing as an important food source. Methylmercury is a potent developmental neurotoxin, especially for developing fetuses. The PAHs are a subset of the polycyclic organic matter (POM), which are a group of HAP that EPA considers to be PB–HAP, and includes some known or probable carcinogens such as benzo-a-pyrene.

3. What are the revised standards for the D/F, PAH and mercury for sinter plants, and how will compliance be demonstrated?

Based on the comments received, we are finalizing emissions limits that reflect the installation and operation of ACI controls, which are emissions limits of 1.1E–08 lbs/ton of sinter for D/F (TEQ), 1.8E–03 lbs/ton of sinter for PAHs, and 1.8E–05 lbs/ton for mercury for existing sinter plant windboxes. Regarding new sources, we are promulgating limits of 1.1E–08 lbs/ton of sinter for D/F (TEQ), 1.5E–03 lbs/ton of sinter for PAHs, and 1.2E–05 lbs/ton for mercury for new sinter plant windboxes. The application of this ACI will achieve significant reductions of mercury, D/F and PAH emissions, important reductions given that all three HAP are highly toxic, persistent, bioaccumulative HAP (PB–HAP), as described above. We estimate these limits for the three separate HAP will result in total combined capital costs of $950K, annualized costs of $2.3M, will achieve 8 grams per year reductions of D/F TEQ emissions, 5.4 tpy reduction in PAHs, and 47 pounds of mercury. The estimated cost effectiveness (CE) for each HAP individually are: CE of $287K per gram D/F TEQ, $426K per ton of PAHs, and $49,000 per pound for mercury.

If the EPA evaluated these emissions limits individually (*i.e.,* without consideration of the co-control of D/F, PAHs and mercury), the EPA might have reached a different conclusion (*e.g.,* maybe not promulgated one or more of the individual final limits due to costs and cost effectiveness). For example, historically, EPA has accepted cost effectiveness for mercury up to about $32,000 per pound. Regarding the D/F and PAHs, we have not identified cost effectiveness values that have been accepted in the past as part of revising standards under EPA's technology reviews pursuant to CAA section 112(d)(6).

However, given that ACI is expected to be needed to achieve the limits for all three HAP (D/F, PAHs and mercury), as described previously in this section, we determined, similar to how we group non-Hg HAP metals when evaluating cost effectiveness, that it is appropriate to consider these three HAP as a group because they would be controlled by the same technology. We note that the Hg cost-effectiveness value is within a factor of 2 of values that we have accepted, and that these three HAP are persistent and bioaccumulative in the environment. Given that ACI is required to achieve the limits for all three PB–HAP (D/F, PAHs and mercury), as described previously in this section, we decided it was appropriate to establish these limits for these three HAP that reflect application of ACI. Because these three pollutants are PB–HAP, as described in more detail in response above, we conclude the estimated costs are reasonable, especially given that these annual costs are far less than 1 percent of revenues for the parent companies, which is discussed further in the economic impacts section of this preamble (see section IV.D).

F. Other Major Comments and Issues

Comment: Commenters stated the EPA's 2023 Proposal for II&S facilities poses many challenges to the domestic iron and steel manufacturing industries. They stated when taken in conjunction with other onerous EPA regulations, including the proposed revisions to the NAAQS for PM, the 2023 Taconite Risk and Technology Review proposal and the 2023 Coke Ovens and Pushing, Quenching, and Battery Stacks Risk and Technology Review proposal, the domestic II&S manufacturers will incur significant cost and will struggle to meet these additional, infeasible standards. They stated it is critical that the EPA understand this 2023 Proposal significantly jeopardizes the potential successes of the Bipartisan Infrastructure Law (BIL) and the Inflation Reduction Act (IRA), and, as a result, undercut the decarbonization priorities of the administration.

Commenters acknowledged the iron and steel industry faces significant impacts from the 2023 Proposal along with other EPA proposed rules including the Taconite MACT, the Coke MACT, the Good Neighbor Rule, and the $PM_{2.5}$ NAAQS. They stated their customers, coworkers, suppliers and themselves are concerned for the future of iron and steelmaking, an essential industry, in the U.S.

Commenters stated the regulations moving through the EPA at the current time are going to materially impact the Iron Range of Minnesota and the entire domestic steel industry. Commenters urged the EPA to be prudent and use caution before placing a single new regulation on these industries. Commenters asked the EPA to show favor in the Agency's decision making to the domestic iron and steel industry.

Response: As explained in the Regulatory Impact Analysis (RIA) and in section IV.D of this preamble, the projected economic impacts of the expected compliance costs of the rule are likely to be small. This rulemaking is estimated to cost less than 1% of the annual revenues of the parent companies. This rule should not be financially detrimental to the source category. See sections IV.C and IV.D of this preamble, and the RIA, for more details.

Comment: Commenters state that in 2020, the EPA conservatively determined that II&S source category risk was well below the acceptable levels established by the Congress and that existing standards are protective of public health with an ample margin of safety, and the proposal does not reopen or even question the EPA's conservative 2020 determination. As the proposal (briefly) recites, ''[i]n the 2020 final rule, the Agency found that risks due to emissions of air toxics from this source category were acceptable and concluded that the NESHAP provided an ample margin of safety to protect public health.'' (2023 Proposal) The EPA's decision not to revisit that conclusion confirms that the EPA supports the 2020 ample margin of safety determination and sees no reason for amendment. In fact, detailed corrected emission and modeling data show that the remaining risks are significantly smaller than even the low levels the EPA estimated in 2020.

Response: The EPA is revising the 2020 final rule to satisfy the *LEAN* decision, which requires the EPA to address any remaining unregulated sources of emissions from the iron and steel facilities. In meeting the requirements of this case law, the EPA collected more data to revisit the standards in the 2020 final rule under a technology review. Therefore, our revised standards are not based on assessment of risk, but instead based on evaluation of additional data. All the standards and other requirements in this final rule are being promulgated pursuant to CAA section 112(d)(2) and (3) or 112(d)(6). The EPA is not promulgating any new or revised standards under CAA section 112(f)(2) or revising its prior risk assessment results and conclusions, but instead are finalizing these standards and other requirements based on evaluation of additional data and applicable 112(d) requirements that direct HAP emission reductions.

Comment: Commenters stated that the EPA's emissions estimates for UFIP sources are flawed and must be corrected. The EPA has attempted to estimate current HAP emission rates for all seven categories of UFIPs, and to estimate emission reductions that it projects would occur if the proposed opacity and work practice standards are achieved. The commenter claims that EPA's emissions estimates are based, in part, on the use of incorrect emission factors, which cause a significant overstatement of emissions from UFIPs, and therefore significantly overestimates risk from UFIPs. These errors result in significant cascading and compounding effects that reveal that the current proposal will be prohibitively expensive and cannot be justified, particularly given the low-risk determination that the EPA has already made.

Response: The EPA disagrees that the UFIP emission factors led to a significant overestimation of emissions from UFIP sources. The emission factors for UFIP sources were developed from the literature, first principles, discussions with the II&S industry, or a combination of all three. The emission factors used for most UFIP sources are described in the memorandum titled *Development of Emissions Estimates for Fugitive or Intermittent HAP Emission Sources for an Example Integrated Iron and Steel Manufacturing Industry Facility for Input to the RTR Risk Assessment* (Docket ID Item No. EPA–HQ–OAR–2002–0083–0956). The emission factor used for bell leaks was lower than the emission factor used in 2019 after incorporating previous feedback from industry that the 2019 emission factor for bell leaks was an overestimation. The emission factor used for bell leaks is described in the memorandum titled *Unmeasured Fugitive and Intermittent Particulate Emissions and Cost Impacts for Integrated Iron and Steel Facilities under 40 CFR part 63, subpart FFFFF* (Docket ID Item No. EPA–HQ–OAR–2002–0083–1447), this document is also referred to as the ''UFIP memorandum'' elsewhere in this preamble.

The PM emission factors for UFIP and capture and control efficiencies for control devices were taken primarily from a relatively recent (2006) EPA document. However, this document used as its primary source of data the 1995 update of the EPA's AP–42 section for the II&S manufacturing industry (section 12.5), which relied upon even older (1970) data in some cases. However, because the 2006 EPA document was developed by the EPA after the II&S manufacturing industry MACT was promulgated and was based on an expert evaluation of the available emission information, it is considered the most reliable source of information about PM emissions for the II&S manufacturing industry available to the EPA and, hence, the most reliable information to be used for UFIP sources.

Other data that were used to estimate UFIP emissions not available in the 2006 EPA document were taken from reliable sources in the literature. In some cases, for the purposes of the II&S manufacturing industry RTR, an emission factor from AP–42 for one II&S manufacturing industry source was used for another II&S manufacturing industry source based on good engineering judgment. For example, if EPA staff determined that the two sources were similar (*e.g.,* used similar processes, equipment, input materials, control devices, etc.), then staff used such a source to estimate emissions from another similar source. If not, staff searched for other relevant information to estimate emissions. Whenever possible, the original source of data referenced by the documents was obtained and reviewed; these references are cited in the ''Example Facility memorandum'' along with the 1995 EPA AP–42 document. Also, where available, AP–42 emission factor quality ratings were provided. In some cases, none of the available literature provided emission factors considered appropriate for today's industry. In these cases, the EPA developed emission factors from basic scientific principles, industry data and feedback, emission factors for similar sources, and the EPA's knowledge of the process. Further explanation and discussion of how emissions were estimated are available in the *Development of Emissions Estimates for Fugitive or Intermittent HAP Emission Sources for an Example Integrated Iron and Steel Manufacturing Industry Facility for Input to the RTR Risk Assessment* (Example facility memorandum) and/or the UFIP memorandum cited previously in this preamble, which are available in the docket for this action.

Comment: Commenters stated the EPA must consider additional data in setting limits. Although the EPA collected data in 2022 from the eight impacted facilities, the commenters urged the EPA to compile and consider additional data before finalizing these 2023 amendments. The limited data collection did not reflect the full range of variability due to seasonal effects and variable operating scenarios. While much of the industry meets the proposed limits at times, the variability may require investment in controls that are currently excluded from the cost estimates in the rules. The EPA must consider additional data and revise the proposed limits to adjust them upwards, as appropriate to account for variability, or eliminate the proposed limit where test results were below detectable levels.

Response: The EPA has made use of all valid test data, both received through the section 114 request in 2022 and submitted during the comment period to establish the emissions limits for sinter plants, BF stoves, BF Primary control devices and BOPF primary control devices. These ''point source'' emissions limits were derived using the UPL methodology using all the valid data. Regarding opacity limits for planned openings and slag processing, we used all valid data for 2022 that we received though the section 114 request in electronic format and that were gathered following the methods, instruction and conditions described in the section 114 request and because these data reflected the most current year. The fenceline monitoring requirements are based on evaluation all the available fenceline monitoring data that EPA received from 16 monitoring sites. EPA considered the variability across all 16 sites to determine the appropriate action level, which is described in detail in the proposed rule preamble published on July 31, 2023 (88 FR 49402). Regarding the work practice standards for Bell Leaks, beaching and unplanned openings, those standards wer developed using data collected through the section 114 requests along with additional data and information collected through public comments. For more details, see the technical memos cited in responses above.

Comment: Commenters stated that the EPA should expand the proposed standards to include best work practices that reduce toxic emissions from steel mills at a minimum by 65% as was shown possible in 2019. Commenters stated that the EPA should ensure air monitoring and testing includes ALL 12 toxic emissions, not simply chromium, as currently proposed.

Response: The change from the 65 percent emission reduction estimated in 2019 to the emission reductions calculated for this rule is primarily due to calculation improvements based on newly received data rather than changes to the set of work practices published. The EPA is finalizing many of the same UFIP work practices that were published for comment in 2019. However, through the 2022 section 114 collection the EPA received information about work practices that are currently being utilized by facilities. The data showed that a subset of the facilities are already utilizing some of the UFIP work practices that are being finalized, which was not taken into account in the baseline emissions estimate conducted in 2019. In the emissions estimate conducted for this rulemaking, baseline emissions were adjusted based on facility-specific information on work practices that are already in use, resulting in lower baseline emissions. If a facility is already using a work practice that is being finalized in this rulemaking, the percent reduction of emissions estimated for that work practice was also removed from the total estimated emission reduction for that facility. The estimated baseline emissions and emission reductions are described in the memorandum titled *Unmeasured Fugitive and Intermittent Particulate Emissions and Cost Impacts for Integrated Iron and Steel Facilities under 40 CFR part 63, subpart FFFFF* (Docket ID Item No. EPA–HQ–OAR–2002–0083–1447).

G. Severability of Standards

This final rule includes MACT standards promulgated under CAA section 112(d)(2)–(3), as well as targeted updates to existing standards and work practices promulgated under section 112(d)(6). We intend each separate portion of this rule to operate independently of and to be severable from the rest of the rule.

First, each set of standards rests on stand-alone scientific determinations that do not rely on judgments made in other portions of the rule. For example, our judgments regarding the 112(d)(2)–(3) MACT Standard for *planned* bleeder valve openings rest on the best performing units' historical data, based on opacity values; in contrast, our judgments regarding 112(d)(6) work practice standards for the basic oxygen process furnace rest on different analyses, including updates to industry standards in practices. Thus, our assessment that the 112(d)(2)–(3) MACT standards are feasible and appropriate is fully independent of our judgments about the 112(d)(6) technology-review-update standards, and vice versa.

Further, EPA also finds that the implementation of each set of CAA 112(d)(2)–(3) MACT standards and each set of 112(d)(6) technology updates, including monitoring requirements, is independent. For example, there is nothing precluding a source from complying with its unplanned bleeder-valve-opening MACT limit, even if that source does not have any data from its fenceline monitors (which measure chromium), and vice versa. Thus, each aspect of EPA's overall approach to this source category could be implemented even in the absence of any one or more of the other elements included in this final rule.

Accordingly, EPA finds that each set of standards in this final rule is severable from and can operate independently of each other set of standards, and at a minimum, that the MACT emissions standards, as a group, are severable from the 112(d)(6) technology update standards (which include the fenceline monitoring requirement).

H. What are the effective and compliance dates?

All affected facilities must continue to comply with the previous provisions of 40 CFR part 63, subpart FFFFF until the applicable compliance date of this final rule. This final action meets the definition in 5 U.S.C. 804(2), so the effective date of the final rule will be 60 days after the promulgation date as specified in the Congressional Review Act. *See* 5 U.S.C. 801(a)(3)(A). The compliance dates are in Table 5. As shown in Table 5, EPA revised compliance dates for some of the final rule requirements. For explanation of revised compliance dates, see section 6 of the RTC.

TABLE 5—SUMMARY OF COMPLIANCE DATES FOR THE FINAL RULE

Source(s)	Rule requirement	Proposed compliance date	Final compliance date
All affected sinter plant windbox sources that commence construction or reconstruction on or before July 31, 2023.	New emissions limits for mercury, HCl, COS, D/F, and PAH.	6 months after the promulgation of the final rule.	3 years after the promulgation date of the final rule.
All affected sources that commence construction or reconstruction on or before July 31, 2023.	Fenceline monitoring requirements	Begin 1 year after the promulgation of the fenceline method for metals or 2 years after the promulgation date of the final rule, whichever is later.	Begin 1 year after the promulgation of the fenceline method for metals or 2 years after the promulgation date of the final rule, whichever is later.
All affected sources that commence construction or reconstruction on or before July 31, 2023.	Opacity limits for Planned Openings, Work Practices for Bell Leaks, and work practices for BOPF Shop.	12 months after the promulgation date of the final rule.	12 months after the promulgation date of the final rule.
All affected sources that commence construction or reconstruction on or before July 31, 2023.	Work Practices and Limits for Unplanned Openings, Work Practices for Beaching, and Opacity limit for Slag Processing.	12 months after the promulgation date of the final rule.	24 months after the promulgation date of the final rule.
All affected BF and BOPF sources that commence construction or reconstruction on or before July 31, 2023.	New emissions limits for HCl, THC, and D/F (see Table 4).	6 months after the promulgation date of the final rule.	3 years after the promulgation date of the final rule.
All affected sources that commence construction or reconstruction after July 31, 2023.	All new and revised provisions	Effective date of the final rule (or upon startup, whichever is later).	Effective date of the final rule (or upon startup, whichever is later).

IV. Summary of Cost, Environmental, and Economic Impacts

A. What are the affected sources?

The affected sources are facilities in the Integrated Iron and Steel Manufacturing Facilities source category. This includes any facility engaged in producing steel from iron ore. Integrated iron and steel manufacturing includes the following processes: sinter production, iron production, iron preparation (hot metal desulfurization), and steel production. The iron production process includes the production of iron in BFs by the reduction of iron-bearing materials with a hot gas. The steel production process includes the BOPF. Based on the data we have, there are eight operating integrated iron and steel manufacturing facilities subject to this NESHAP, and one idle facility.

B. What are the air quality impacts?

We project emissions reductions of about 64 tpy of HAP metals and about 473 tpy of $PM_{2.5}$ from UFIP sources in the Integrated Iron and Steel Manufacturing Facilities source category due to the new and revised standards for UFIP sources.

C. What are the cost impacts?

The estimated capital costs are the same as the proposed estimate at $5.4M and annualized costs are $2.8M per year for the source category for the new UFIP control requirements. Also, compliance testing for all the new standards is estimated to cost the same as the proposed estimate at about $1.7M once every 5 years for the source category (which equates to about an average of roughly $320,000 per year). The estimated cost breakdown for the fenceline monitoring requirement is the same as proposed at $25,000 capital cost and $41,100 annual operating costs per monitor, $100,000 capital costs and $164,000 annual operating costs per facility, and $800,000 capital costs and $1.3M annual operating costs for the source category (assumes 8 operating facilities). Additional monitoring, recordkeeping, and reporting requirements associated with the final rule are expected to cost the same as the proposed estimate at $7,500 per facility per year ($60,000 for the source category per year, assuming eight facilities). The cost estimates were primarily revised in response to modifications of the rule requirements, with some BTF components being substituted for MACT floor options, as well as in response to contractor revisions. Additional adjustments were made to recategorize some annual costs that were initially miscategorized as capital costs. Based on the comments received, emission limits for sinter plants were revised to reflect the installation of ACI controls. ACI controls on the sinter plants are expected to cost $950,000 in total capital cost and $2.3 million in total annual cost. The total estimated capital costs are $7.1 million and total estimated annualized costs are $6.7 million for all the requirements for the source category. However, annual costs could decrease after facilities complete 2 years of fenceline monitoring because we have included a sunset provision whereby if facilities remain below the one half of the action level for 2 full years, they can request to terminate the fenceline monitoring. Termination of the fenceline monitoring in no way impacts the requirement for facilities to meet all other obligations under this subpart including the general duty to minimize emissions of 40 CFR 63.7810(d). There may be some energy savings from reducing leaks of BF gas from bells, which is one of the work practices described in this preamble, however those potential savings have not been quantified.

D. What are the economic impacts?

The EPA conducted an economic impact analysis for the final rule in the Regulatory Impact Analysis (RIA), which is available in the docket for this action. If the compliance costs, which are key inputs to an economic impact analysis, are small relative to the receipts of the affected industries, then the impact analysis may consist of a calculation of annual (or annualized) costs as a percent of sales for affected parent companies. This type of analysis is often applied when a partial equilibrium, or more complex economic impact analysis approach, is deemed unnecessary, given the expected size of the impacts. The annualized cost per sales for a company represents the maximum price increase in the affected product or service needed for the company to completely recover the annualized costs imposed by the regulation. We conducted a cost-to-sales analysis to estimate the economic impacts of this final action, given that the EAV of the compliance costs over the period 2026–2035 are $5.1 million using a 7 percent or $5.3 million using a 3 percent discount rate in 2022 dollars, which is small relative to the revenues of the steel industry.

There are two parent companies directly affected by the rule: Cleveland-Cliffs, Inc. and U.S. Steel. Each reported greater than $20 billion in revenue in 2021. The EPA estimated the annualized compliance cost each firm is expected to incur and determined the estimated cost-to-sales ratio for each firm is less than 0.02 percent. Therefore, the projected economic impacts of the expected compliance costs of the rule are likely to be small. The EPA also conducted a small business screening to determine the possible impacts of the rule on small businesses. Based on the Small Business Administration size standards and Cleveland-Cliffs, Inc. and U.S. Steel employment information, this source category has no small businesses.

E. What are the benefits?

The UFIP emissions work practices to reduce HAP emissions (with concurrent control of $PM_{2.5}$) are anticipated to improve air quality and the health of persons living in surrounding communities. The opacity limits and UFIP work practices are expected to reduce about 64 tpy of HAP metal emissions, including emissions of manganese, lead, arsenic, and chromium. Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAP in this analysis. Instead, we are providing a qualitative discussion of the health effects associated with HAP emitted from sources subject to control under the rule in section 4.2 of the RIA, available in the docket for this action. The EPA remains committed to improving methods for estimating HAP-reduction benefits by continuing to explore additional aspects of HAP-related risk from the integrated iron and steel manufacturing sector, including the distribution of that risk.

The opacity limits and UFIP work practices are also estimated to reduce $PM_{2.5}$ emissions by about 473 tpy for the source category. The EPA estimated monetized benefits related to avoided premature mortality and morbidity associated with reduced exposure to $PM_{2.5}$ for 2026–2035. The present-value (PV) of the short-term benefits for the rule are estimated to be $1.8 billion at a 3 percent discount rate and $1.2 billion at a 7 percent discount rate with an equivalent annualized value (EAV) of $200 million and $170 million, respectively. The EAV represents a flow of constant annual values that would yield a sum equivalent to the PV. The PV of the long-term benefits for the rule range are estimated to be $3.7 billion at a 3 percent discount rate and $2.6 billion at a 7 percent discount rate with an EAV of $420 million and $340 million, respectively. All estimates are reported in 2022 dollars. For the full set of underlying calculations see the *Integrated Iron and Steel Benefits workbook,* available in the docket for this action.

F. What analysis of environmental justice did we conduct?

To examine the potential for any EJ issues that might be associated with Integrated Iron and Steel Manufacturing Facilities sources, we performed a proximity demographic assessment, which is an assessment of individual demographic groups of the populations living within 5 kilometers (km) and 50 km of the facilities. The EPA then compared the data from this assessment to the national average for each of the demographic groups. This assessment did not inform and was not used to develop the amended standards established in the final action. The amended standards were established based on the technical and scientific determinations described herein.

The EPA defines EJ as ''the just treatment and meaningful involvement of all people regardless of income, race, color, national origin, Tribal affiliation, or disability, in agency decision-making and other Federal activities that affect human health and the environment so that people: (i) are fully protected from disproportionate and adverse human health and environmental effects (including risks) and hazards, including those related to climate change, the cumulative impacts of environmental and other burdens, and the legacy of racism or other structural or systemic barriers; and (ii) have equitable access to a healthy, sustainable, and resilient environment in which to live, play, work, learn, grow, worship, and engage in cultural and subsistence practices.'' [5] In recognizing that communities with EJ concerns often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action may involve potential EJ concerns if it could: (1) create new disproportionate impacts on communities with EJ concerns; (2) exacerbate existing disproportionate impacts on communities with EJ concerns; or (3) present opportunities to address existing disproportionate impacts on communities with EJ concerns through this action under development.

The EPA's EJ technical guidance states that ''[t]he analysis of potential EJ concerns for regulatory actions should address three questions: (A) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline? (B) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration? (C) For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?''[1]

The results of the proximity demographic analysis (see Table 6) indicate that, for populations within 5 km of the nine integrated iron and steel facilities, the percent of the population that is Black is more than twice the national average (27 percent versus 12 percent). In addition, the percentage of the population that is living below the poverty level (29 percent) and living below 2 times the poverty level (52 percent) is well above the national average (13 percent and 29 percent, respectively). Other demographics for the populations living within 5 km are below or near their respective national averages.

Within 50 km of the nine sources within the Integrated Iron and Steel Manufacturing Facilities category, the percent of the population that is Black is above the national average (20 percent versus 12 percent). Within 50 km the income demographics are similar to the national averages. Other demographics for the populations living within 50 km are below or near the respective national averages.

The methodology and the results of the demographic analysis are presented in the document titled *Analysis of Demographic Factors for Populations Living Near Integrated Iron and Steel Facilities,* which is available in the docket for this action.

As discussed in other subsections of the impacts of this action, in this action the EPA is adding requirements for facilities to improve UFIP emission control resulting in reductions of both metal HAP and $PM_{2.5}$. We estimate that all facilities will achieve reductions of HAP emissions as a result of this rule, including the facilities at which the percentage of the population living in close proximity who are Black and below poverty level is greater than the national average. The rule changes will have beneficial effects on air quality and public health for populations exposed to emissions from integrated iron and steel facilities.

TABLE 6—PROXIMITY DEMOGRAPHIC ASSESSMENT RESULTS FOR INTEGRATED IRON AND STEEL MANUFACTURING FACILITIES

Demographic group	Nationwide	Population within 50 km of 9 facilities	Population within 5 km of 9 facilities
Total Population	329,824,950	18,966,693	478,761
	Race and Ethnicity by Percent		
White	60	63	52
Black	12	20	27
Native American	0.6	0.1	0.2
Hispanic or Latino (includes white and nonwhite)	19	10	16
Other and Multiracial	9	7	5
	Income by Percent		
Below Poverty Level	13	13	29
Above Poverty Level	87	87	71
Below 2x Poverty Level	29	28	52
Above 2x Poverty Level	71	72	48
	Education by Percent		
Over 25 and without a High School Diploma	12	9	18
Over 25 and with a High School Diploma	88	91	82

---

[5] *https://www.federalregister.gov/documents/2023/04/26/2023-08955/revitalizing-our-nations-commitment-to-environmental-justice-for-all.*

TABLE 6—PROXIMITY DEMOGRAPHIC ASSESSMENT RESULTS FOR INTEGRATED IRON AND STEEL MANUFACTURING FACILITIES—Continued

Demographic group	Nationwide	Population within 50 km of 9 facilities	Population within 5 km of 9 facilities
	Linguistically Isolated by Percent		
Linguistically Isolated	5	3	6

Notes:

- The nationwide population count and all demographic percentages are based on the Census' 2016–2020 American Community Survey five-year block group averages and include Puerto Rico. Demographic percentages based on different averages may differ. The total population counts are based on the 2020 Decennial Census block populations.
- To avoid double counting, the "Hispanic or Latino" category is treated as a distinct demographic category for these analyses. A person is identified as one of five racial/ethnic categories above: White, African American, Native American, Other and Multiracial, or Hispanic/Latino. A person who identifies as Hispanic or Latino is counted as Hispanic/Latino for this analysis, regardless of what race this person may have also identified as in the Census.

In addition to the analyses described above, the EPA completed a risk-based demographics analysis for the residual risk and technology review (RTR) proposed rule (84 FR 42704, August 16, 2019) and the 2020 RTR final rule (85 FR 42074, July 13, 2020). A description of the demographic analyses and the results are provided in those two **Federal Register** notices.

V. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a ''significant regulatory action'' as defined under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094. Accordingly, EPA, submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Any changes made in response to recommendations received as part of Executive Order 12866 review have been documented in the docket.

B. Paperwork Reduction Act (PRA)

The information collection activities in this final action have been submitted for approval to OMB under the PRA. The information collection request (ICR) document that the EPA prepared has been assigned EPA ICR number 2003.10. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

Respondents/affected entities: Integrated iron and steel manufacturing facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart FFFFF).

Estimated number of respondents: 8 facilities.

Frequency of response: One time.

Total estimated burden: The annual recordkeeping and reporting burden for facilities to comply with all of the requirements in the NESHAP is estimated to be 30,400 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: The annual recordkeeping and reporting cost for all facilities to comply with all of the requirements in the NESHAP is estimated to be $3,950,000 per year, of which $3,140,000 per year is for this final rule, and $803,000 is for other costs related to continued compliance with the NESHAP including $108,000 for paperwork associated with operation and maintenance requirements.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. The Agency confirmed through responses to a CAA section 114 information request that there are only eight integrated iron and steel manufacturing facilities currently operating in the United States and that these plants are owned by two parent companies that do not meet the definition of small businesses, as defined by the U.S. Small Business Administration.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local, or Tribal governments or the private sector.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the National Government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes. No tribal governments own facilities subject to the NESHAP. Thus, Executive Order 13175 does not apply to this action.

G. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This action involves technical standards. Therefore, the EPA conducted searches for the Integrated Iron and Steel Manufacturing Facilities NESHAP through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute

(ANSI). We also conducted voluntary consensus standards (VCS) organizations and accessed and searched their databases. We conducted searches for EPA Methods 1, 2, 2F, 2G, 3, 3A, 3B, 4, 5, 5D, 9, 17, 23, 25A, 26A, 29, and 30B of 40 CFR part 60, appendix A, 320 of 40 CFR part 63 appendix, and SW–846 Method 9071B. During the EPA's VCS search, if the title or abstract (if provided) of the VCS described technical sampling and analytical procedures that are similar to the EPA's referenced method, the EPA ordered a copy of the standard and reviewed it as a potential equivalent method. We reviewed all potential standards to determine the practicality of the VCS for this rule. This review requires significant method validation data that meet the requirements of EPA Method 301 for accepting alternative methods or scientific, engineering, and policy equivalence to procedures in the EPA referenced methods. The EPA may reconsider determinations of impracticality when additional information is available for particular VCS.

No applicable VCS was identified for EPA Methods 1, 2, 2F, 2G, 3, 3A, 3B, 4, 5, 5D, 9, 17, 23, 25A, 26A, 29, 30B and SW–846 Method 9071B not already incorporated by reference in this subpart. The search identified one VCS that was potentially applicable for this rule in lieu of EPA Method 29. After reviewing the available standard, the EPA determined that the VCS identified for measuring emissions of pollutants subject to emissions standards in the rule would not be practical due to lack of equivalency. The EPA incorporates by reference VCS ASTM D6348–12 (Reapproved 2020), ''Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy,'' as an acceptable alternative to EPA Method 320 of appendix A to 40 CFR part 63 with caveats requiring inclusion of selected annexes to the standard as mandatory. The ASTM D6348–12 (R2020) method is an extractive FTIR spectroscopy-based field test method and is used to quantify gas phase concentrations of multiple target compounds in emission streams from stationary sources. This field test method provides near real time analysis of extracted gas samples. In the September 22, 2008, NTTAA summary, ASTM D6348–03(2010) was determined equivalent to EPA Method 320 with caveats. ASTM D6348–12 (R2020) is a revised version of ASTM D6348–03(2010) and includes a new section on accepting the results from direct measurement of a certified spike gas cylinder, but still lacks the caveats we placed on the D6348–03(2010) version. We are finalizing that the test plan preparation and implementation in the Annexes to ASTM D 6348–12 (R2020), Annexes Al through A8 are mandatory; and in ASTM D6348–12 (R2020) Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5). We are finalizing that, 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:

$$Reported\ Results = \frac{Stack\ Concentration}{\%R} = 100$$

The ASTM D6348–12 (R2020) method is available at ASTM International, 1850 M Street NW, Suite 1030, Washington, DC 20036. See *www.astm.org/.*

The EPA is also incorporating by reference Quality Assurance Handbook for Air Pollution Measurement Systems, Volume IV: Meteorological Measurements, Version 2.0 (Final), March 2008 (EPA–454/B–08–002). The Quality Assurance Handbook for Air Pollution Measurement Systems; Volume IV: Meteorological Measurements is an EPA developed guidance manual for the installation, operation, maintenance and calibration of meteorological systems including the wind speed and direction using anemometers, temperature using thermistors, and atmospheric pressure using aneroid barometers, as well as the calculations for wind vector data for on-site meteorological measurements. This VCS may be obtained from the EPA's National Service Center for Environmental Publications (*www.epa.gov/nscep*).

Additional information for the VCS search and determination can be found in the memorandum, *Voluntary Consensus Standard Results for National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing,* which is available in the docket for this action.

ASTM D7520–16 is already approved for the location in which it appears in the amendatory text.

H. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

The EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with EJ concerns. For this action the EPA conducted an assessment of the various demographic groups living near Integrated Iron and Steel facilities (as described in section V.F of this preamble) that might potentially be impacted by emissions from Integrated Iron and Steel Facilities. For populations living within 5 km of the nine integrated iron and steel facilities, the percent of the population that is Black is more than twice the national average (27 percent versus 12 percent). Specifically, within 5 km of six of the nine facilities, the percent of the population that is Black is more than 1.5 times the national average (ranging between 1.5 times and 7 times the national average). The percentage of the population that is living below the poverty level (29 percent) and living below 2 times the poverty level (52 percent) is well above the national average (13 percent and 29 percent, respectively). Specifically, within 5 km of seven of the nine facilities, the percent of the population that is living below the poverty level is more than 1.5 times the national average (ranging from 1.5 times and 3 times the national average). Other demographics for the populations living within 5 km are below or near the respective national averages.

The EPA believes that this action is likely to reduce existing disproportionate and adverse effects on communities with EJ concerns. This action requires facilities to improve UFIP emission control resulting in reductions of about 64 tpy of metal HAP and about 473 tpy $PM_{2.5}$. We estimate that all facilities will achieve reductions of HAP emissions as a result of this rule, including the facilities at which the percentage of the population living in close proximity who are African American and below poverty level is greater than the national average.

The information supporting this Executive Order review is contained in sections IV and V of this preamble. The demographic analysis is available in a document titled *Analysis of Demographic Factors for Populations Living Near Integrated Iron and Steel Facilities,* which is available in the docket for this action.

I. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045 (62 FR 19885, April 23, 1997) directs federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is not subject to Executive Order 13045 because the EPA does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children.

J. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. We have concluded that this action is not likely to have any adverse energy effects because it contains no regulatory requirements that will have an adverse impact on productivity, competition, or prices in the energy sector.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit the rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Hydrogen chloride, Hydrogen fluoride, Incorporation by reference, Mercury, Reorting and recordkeeping requirements.

Michael S. Regan,
Administrator.

For the reasons stated in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 4701, *et seq.*

Subpart A—General Provisions

■ 2. Section 63.14 is amended by revising paragraphs (i)(88) and (110) and paragraph (o) introductory text and adding paragraph (o)(3) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(i) * * *

(88) ASTM D6348–12 (Reapproved 2020), Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy, including Annexes A1 through A8, Approved December 1; 2020, IBR approved for §§ 63.365(b); *63.7825(g)* and *(h).*

* * * * *

(110) ASTM D7520–16, Standard Test Method for Determining the Opacity of a Plume in the Outdoor Ambient Atmosphere, approved April 1, 2016; IBR approved for §§ 63.1625(b); table 3 to subpart LLLLL; 63.7823(c) through (f), 63.7833(g); 63.11423(c).

* * * * *

(o) U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue NW, Washington, DC 20460; phone: (202) 272–0167; website: *www.epa.gov/aboutepa/forms/contact-epa.*

* * * * *

(3) EPA–454/B–08–002, Quality Assurance Handbook for Air Pollution Measurement Systems; Volume IV: Meteorological Measurements, Version 2.0 (Final), Issued March 2008, IBR approved for § 63.7792(b).

* * * * *

Subpart FFFFF—National Emission Standards for Hazardous Air Pollutants for Integrated Iron and Steel Manufacturing Facilities

■ 3. Amend § 63.7782 by revising paragraphs (c), (d), and (e) to read as follows:

§ 63.7782 What parts of my plant does this subpart cover?

* * * * *

(c) This subpart covers emissions from the sinter plant windbox exhaust, discharge end, and sinter cooler; the blast furnace casthouse; the blast furnace stove; and the BOPF shop including each individual BOPF and shop ancillary operations (hot metal transfer, hot metal desulfurization, slag skimming, and ladle metallurgy). This subpart also covers fugitive and intermittent particulate emissions from blast furnace unplanned bleeder valve openings, blast furnace planned bleeder valve openings, blast furnace and BOPF slag processing, handling, and storage, blast furnace bell leaks, beaching of iron from blast furnaces, blast furnace casthouse fugitives, and BOPF shop fugitives.

(d) A sinter plant, blast furnace, blast furnace stove, or BOPF shop at your integrated iron and steel manufacturing facility is existing if you commenced construction or reconstruction of the affected source before July 13, 2001.

(e) A sinter plant, blast furnace, blast furnace stove, or BOPF shop at your integrated iron and steel manufacturing facility is new if you commence construction or reconstruction of the affected source on or after July 13, 2001. An affected source is reconstructed if it meets the definition of reconstruction in § 63.2.

■ 4. Amend § 63.7783 by revising paragraph (a) introductory text and adding paragraph (g) to read as follows:

§ 63.7783 When do I have to comply with this subpart?

(a) If you have an existing affected source, you must comply with each emission limitation, standard, and operation and maintenance requirement in this subpart that applies to you by the dates specified in paragraphs (a)(1) and (2) of this section. This paragraph does not apply to the emission limitations for BOPF group: mercury (Hg); sinter plant windbox: Hg, hydrochloric acid (HCl), carbonyl sulfide (COS); Blast Furnace casthouse: HCl, total hydrocarbon (THC); Blast Furnace stove: HCl and total hydrocarbon (THC); primary emission control system for a BOPF: 2,3,7,8-tetrachlorodibenzo-p-dioxin (2,3,7,8–TCDD) toxic equivalent (TEQ), HCl, THC; fugitive and intermittent particulate sources.

* * * * *

(g) If you have an existing affected source or a new or reconstructed affected source for which construction or reconstruction commenced on or before July 31, 2023, each sinter plant windbox, BF casthouse, BF stove, primary emission control system for a BOPF, and fugitive and intermittent particulate source at your facility must be in compliance with the applicable emission limits in table 1 of this subpart through performance testing under § 63.7825, April 3, 2025, except for the following:

(1) All affected sinter plant windbox sources that commence construction or reconstruction on or before July 31, 2023, must be in compliance with Hg, HCl, COS, TEQ, and PAH emissions limits in table 1 to this subpart through performance testing by April 3, 2027.

(2) All affected BF and BOPF sources that commence construction or reconstruction on or before July 31, 2023, must be in compliance with HCl, THC, and TEQ emissions limits in table 1 to this subpart through performance testing by April 3, 2027.

(3) All affected sources that commence construction or reconstruction on or before July 31, 2023 must be in compliance with work practices and limits for unplanned openings, work practices for beaching, and the opacity limit for slag processing in table 1 to this subpart through performance testing (or through reporting of number of unplanned openings for limits applicable to unplanned openings shown in table 1) by April 3, 2026.

(4) All affected sources that commence construction or reconstruction after July 31, 2023, must be in compliance with all new and revised provisions in table 1 to this subpart through performance testing by April 3, 2024 or upon startup, whichever is later.

■ 5. Amend § 63.7791 by revising the section heading to read as follows:

§ 63.7791 How do I comply with the requirements for the control of mercury from BOPF Groups?

* * * * *

■ 6. Add § 63.7792 to read as follows:

§ 63.7792 What fenceline monitoring requirements must I meet?

The owner or operator must conduct sampling along the facility property boundary and analyze the samples in accordance with paragraphs (a) through (g) of this section.

(a) Beginning either 1 year after promulgation of the test method for fenceline sampling of metals applicable to this subpart or April 3, 2026 whichever is later, the owner or operator must conduct sampling along the facility property boundary and analyze the samples in accordance with the method and paragraphs (a)(1) through (3) of this section.

(1) The owner or operator must monitor for total chromium.

(2) The owner or operator must use a sampling period and sampling frequency as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) *Sampling period.* A 24-hour sampling period must be used. A sampling period is defined as the period during active collection of a sample and does not include the time required to analyze the sample.

(ii) *Sampling frequency.* The frequency of sample collection must be samples at least every 6 calendar days, such that the beginning of each sampling period begins no greater than approximately 144 hours (±12 hours) from the end of the previous sample.

(iii) *Sunset provision.* When the annual rolling average Δc remains less than 0.05 µg/m^3 for 24 months in succession, a test waiver may be requested from the Administrator to remove or reduce fenceline sampling requirements. If the annual rolling average Δc exceeds 0.05µg/m^3, the determination of 24 consecutive annual average Δc months restarts.

(3) The owner or operator must determine sample locations in accordance with paragraphs (b)(3)(i) through (v) of this section.

(i) The monitoring perimeter must be located between the property boundary and the process unit(s), such that the monitoring perimeter encompasses all potential sources of the target analyte(s) specified in paragraph (a)(1) of this section.

(ii) The owner or operator must place a minimum of 4 samplers around the monitoring perimeter.

(iii) To determine sampling locations, measure the length of the monitoring perimeter.

(A) Locate the point downwind of the prevailing wind direction.

(B) Divide the monitoring perimeter equally into 4 evenly spaced sampling points, with one located in accordance with paragraph (a)(3)(iii)(A) of this section.

(4) The owner or operator must follow the procedures in of the fenceline metals test method to determine the detection limit of the target analyte(s) and requirements for quality assurance samples.

(b) The owner or operator must collect and record meteorological data according to the applicable requirements in paragraphs (b)(1) through (3) of this section.

(1) If monitoring is conducted under paragraph (b) of this section, if a near-field source correction is used as provided in paragraph (f)(2) of this section, or if an alternative test method is used that provides time-resolved measurements, the owner or operator must use an on-site meteorological station in accordance with the metals fenceline test method applicable to this subpart. 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 (c)(1) of this section, the owner or operator must collect and record sampling period average temperature and barometric pressure using either an on-site meteorological station in accordance with the metals fenceline test method of this part or, alternatively, using data from a National Weather Service (NWS) meteorological station provided the NWS meteorological station is within 40 kilometers (25 miles) of the facility.

(3) If an on-site meteorological station is used, the owner or operator must follow the calibration and standardization procedures for meteorological measurements in EPA–454/B–08–002 (incorporated by reference, see § 63.14).

(c) Within 45 days of completion of each sampling period, the owner or operator must determine whether the results are above or below the action level as follows.

(1) The owner or operator must determine the facility impact on the concentration (Δc) for each sampling period according to either paragraph (d)(1)(i) or (ii) of this section, as applicable.

(i) Except when near-field source correction is used as provided in paragraph (d)(1)(ii) of this section, the owner or operator must determine the highest and lowest sample results individually from the sample pool and calculate the Δc as the difference in these concentrations. Co-located samples must be averaged together for the purposes of determining the concentration at a particular sampling location, and, if applicable, for determining Δc. The owner or operator must adhere to the following procedures when one or more samples for the sampling period are below the method detection limit for a particular compound:

(A) If the lowest detected value is below detection, the owner or operator must 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 must use the highest method detection limit for the sample set as the highest sample result and zero as the lowest sample result when calculating Δc.

(ii) When near-field source correction is used as provided in paragraph (g) of this section, the owner or operator must determine Δc using the calculation protocols outlined in the approved site-specific monitoring plan and in paragraph (g) of this section.

(2) The owner or operator must calculate the annual average Δc based on the average of the Δc values for the 61 most recent sampling periods. The owner or operator must update this annual average value after receiving the results of each subsequent sampling period.

(3) The action level for chromium is 0.1 μg/m³. If the annual average Δc value (rounded to 1 significant figure) is greater than the action level, the concentration is above the action level, and the owner or operator must conduct a root cause analysis and corrective action in accordance with paragraph (d) of this section.

(d) Once any action level in paragraph (c)(3) of this section has been exceeded, the owner or operator must take the following actions to bring the annual average Δc back below the action level(s).

(1) Within 5 days of updating the annual average value as required in (c)(2) and determining that any action level in paragraph (c)(3) of this section has been exceeded (*i.e.,* in no case longer than 50 days after completion of the sampling period), the owner or operator must initiate a root cause analysis to determine appropriate corrective action. A root cause analysis is an assessment conducted through a process of investigation to determine the primary underlying cause and all other contributing causes to an exceedance of the action level(s) set forth in paragraph (c)(3).

(2) The initial root cause analysis may include, but is not limited to:

(i) Visual inspection to determine the cause of the high emissions.

(ii) Operator knowledge of process changes (*e.g.,* a malfunction or release event).

(3) If the initial root cause cannot be identified using the type of techniques described in paragraph (d)(2) of this section, the owner or operator must employ more frequent sampling and analysis to determine the root cause of the exceedance.

(i) The owner or operator may first employ additional monitoring points or more frequent sampling to determine the root cause of the exceedance.

(ii) If the owner or operator has not determined the root cause of the exceedance within 30 days of determining that the action level has been exceeded, the owner or operator must employ the appropriate more time resolute sampling techniques (*e.g.,* continuous multi metals monitors) to locate the cause of the exceedance. If the root cause is not identified after 28 days, either the more time resolute monitor must be relocated or an additional more time resolute monitor must be added. Relocation or addition of extra monitors must continue after each 28-day period of nonidentification until the owner or operator can identify the root cause of the exceedance.

(4) If the underlying primary and other contributing causes of the exceedance are deemed to be under the control of the owner or operator, the owner or operator must take appropriate corrective action as expeditiously as possible to bring annual average fenceline concentrations back below the action level(s) set forth in paragraph (c)(2)(3) of this section. At a minimum, the corrective actions taken must address the underlying primary and other contributing cause(s) determined in the root cause analysis to prevent future exceedances from the same underlying cause(s).

(5) The root cause analysis must be completed and initial corrective actions taken no later than 45 days after determining there is an exceedance of an action level.

(e) An owner or operator must develop a corrective action plan if the conditions in either paragraph (e)(1) or (2) of this section are met. The corrective action plan must describe the corrective action(s) completed to date, additional measures that the owner or operator proposes to employ to expeditiously reduce annual average fenceline concentrations below the action level set forth in paragraph (c)(3) of this section, and a schedule for completion of these measures. The corrective action plan must identify actions to address the underlying primary and other contributing cause(s) determined in the root cause analysis to prevent future exceedances from the same underlying cause(s). The corrective action plan does not need to be approved by the Administrator. However, if upon review, the Administrator disagrees with the additional measures outlined in the plan, the owner or operator must revise and resubmit the plan within 7 calendar days of receiving comments from the Administrator.

(1) The owner or operator must develop a corrective action plan if, upon completion of the root cause analysis and initial corrective actions required in paragraph (d) of this section, the Δc value for the next sampling period, for which the sampling start time begins after the completion of the initial corrective actions, is greater than 0.1 μg/m³. The owner or operator must submit the corrective action plan to the Administrator within 60 days after receiving the analytical results indicating that the Δc value for the sampling period following the completion of the initial corrective action is greater than 0.1 μg/m³.

(2) The owner or operator must develop a corrective action plan if complete implementation of all corrective measures identified in the root cause analysis required by paragraph (d) of this section will require more than 45 days. The owner or operator must submit the corrective action plan to the Administrator no later than 60 days following the completion of the root cause analysis required in paragraph (d) of this section.

(f) An owner or operator may request approval from the Administrator for a site-specific monitoring plan to account for offsite upwind sources according to the requirements in paragraphs (f)(1) through (4) of this section.

(1) The owner or operator must 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 (f)(2) of this section. The site-specific monitoring plan must include, at a minimum, the elements specified in paragraphs (f)(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.

(ii) Location of the additional monitoring stations that must be used to determine the uniform background concentration and the near-field source concentration contribution. Modeling may not be used in lieu of monitoring to identify uniform background concentration and near-field sources.

(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 including the treatment of invalid data, data below detection limits, and data collected during calm wind periods; and calculations to determine the near-field source concentration contribution for each monitoring location.

(v) A detailed description of the measurement technique, measurement location(s), the standard operation procedure, measurement frequency, recording frequency, measurement detection limit, and data quality indicators to ensure accuracy, precision, and validity of the data.

(2) When an approved site-specific monitoring plan is used, the owner or operator must determine Δc for comparison with the action level using the requirements specified in paragraphs (f)(2)(i) through (iii) of this section.

(i) For each monitoring location, calculate Δc_i using the following equation.

Equation 1 to paragraph (f)(1)(i)

$$\Delta c_i = MFC_i - NFS_i$$

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.

(ii) When one or more samples for the sampling period are below the method detection limit, adhere to the following procedures:

(A) If the 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 must use zero for the monitoring location concentration when calculating NFS_i for that monitoring period.

(B) If a fenceline monitoring location sample result is below the method detection limit, the owner or operator must 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 must be submitted and approved as described in paragraphs (f)(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 must 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: Integrated Iron and Steel Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *fencelineplan@epa.gov.*

(iii) The Administrator will approve or disapprove the plan in 90 days. The plan is considered approved if the Administrator either approves the plan in writing or fails to disapprove the plan in writing. The 90-day period begins 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 (f)(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 (f)(4)(i) through (v) of this section.

(i) The identification of the near-field source or sources and evidence of how the sources impact the fenceline concentrations.

(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, including the handling of invalid data, data below the detection limit, and data during calm periods.

(vi) If more frequent monitoring is proposed, the adequacy of the description of and rationale for the measurement technique, measurement location(s), the standard operation procedure, measurement frequency, recording frequency, measurement detection limit, and data quality indicators to ensure accuracy, precision, and validity of the data.

(g) The owner or operator must comply with the applicable recordkeeping and reporting requirements in § 63.7841 and § 63.7842.

(1) 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 (f)(1)(i) through (vi) of this section.

(i) The alternative method may be used in lieu of all or a partial number of the sampling locations required under paragraph (a) of this section.

(ii) 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.

(iii) The method detection limit must nominally be at least three times below the action level. The alternate test method must describe the procedures used to provide field verification of the detection limit.

(iv) If the alternative test method will be used to replace some or all samplers required under paragraph (a) of this section, the spatial coverage must be equal to or better than the spatial coverage provided under paragraph (a).

(v) 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.

(vi) For purposes of averaging data points to determine the Δc for the individual sampling period, all results measured under the method detection limit must use the method detection limit. For purposes of averaging data points for the individual sampling period low sample result, all results measured under the method detection limit must use zero.

■ 7. Add § 63.7793 to read as follows:

§ 63.7793 What work practice standards must I meet?

(a) You must meet each work practice limit in table 1 to this subpart that applies to you.

(b) For unplanned bleeder valve openings on a new and existing blast furnace, you must meet each work practice standard listed in paragraphs (b)(1) through (3) of this section.

(1) Develop and operate according to a ''Slip Avoidance Plan'' to minimize slips and submit it to EPA for approval;

(2) Install devices to continuously measure/monitor material levels in the furnace (*i.e.,* stockline), at a minimum of three locations, with alarms to inform operators of static (*i.e.,* not moving) stockline conditions which increase the likelihood of slips; and

(3) Install and use instruments on the furnace to monitor temperature and pressure to help determine when a slip is likely to occur.

(c) For each large bell on a new and existing blast furnace, you must meet each work practice standard listed in paragraphs (c)(1) and (2) of this section.

(1) Maintain metal seats to minimize wear on seals and emissions; and

(2) Replace or repair large bell seals according to § 63.7833(j).

(d) For each small bell on a new and existing blast furnace, you must meet each work practice standard listed in paragraphs (d)(1) and (2) of this section.

(1) Maintain metal seats to minimize wear on seals; and

(2) You must repair or replace small bell seals prior to the time period or metal throughput limit that has been proven and documented to produce no opacity from the small bell.

(e) For each iron beaching operation, you must meet each work practice standard listed in paragraphs (e)(1) and (2) of this section.

(1) Minimize the drop height of molten metal to the ground, the slope or grade of the area where beaching occurs, and the rate at which molten metal is poured onto the ground; and

(2) Use carbon dioxide shielding during beaching event; and/or use full or partial (hoods) enclosures around beached iron.

(f) For each BOPF at a new or existing shop, you must develop and operate according to a ''BOPF Shop Operating Plan'' to minimize fugitive emissions and detect openings and leaks and submit it to EPA for approval. Your BOPF Shop Operating Plan may include, but is not limited to, any of the items listed in paragraphs (f)(1) through (8) of this section.

(1) List all events that generate VE, including slopping and other steps company will take to reduce incidence rate. State the specific actions that operators will take when slag foaming approaches the mouth of the vessel in order to prevent slopping;

(2) Minimize hot iron pour/charge rate (minutes) and set a maximum pour rate in tons/second;

(3) Schedule of regular inspections of BOPF shop structure for openings and leaks to the atmosphere;

(4) Optimize positioning of hot metal ladles with respect to hood face and furnace mouth;

(5) Optimize furnace tilt angle during charging and set a maximum tilt angle during charging;

(6) Keep all openings, except roof monitors, closed, especially during transfer, to extent feasible and safe. All openings shall be closed unless the opening was in the original design of the Shop;

(7) Use higher draft velocities to capture more fugitives at a given distance from hood, if possible; and

(8) Monitor opacity periodically (*e.g.,* once per month) from all openings with EPA Method Alt-082 (camera) or with EPA Method 9 in appendix A–4 to part 60 of this chapter.

■ 8. Amend § 63.7800 by revising paragraph (b) introductory text and adding paragraphs (b)(8) and (9) to read as follows:

§ 63.7800 What are my operation and maintenance requirements?

* * * * *

(b) You must prepare and operate at all times according to a written operation and maintenance plan for each capture system or control device subject to an operating limit in § 63.7790(b). Each plan must address the elements in paragraphs (b)(1) through (9) of this section.

* * * * *

(8) Small Bell repair or replacement period, in weeks, or mass of material throughput, in tons, and the specific begin date and end date for the chosen repair or replacement period or throughput over which there were no visible emissions observed.

(9) Building drawings of the BF Casthouse and BOPF shop that show and list by number the openings, including doors and vents, that are part of the original design of the building.

■ 9. Amend § 63.7820 by revising paragraph (e) to read as follows:

§ 63.7820 By what date must I conduct performance tests or other initial compliance demonstrations?

* * * * *

(e) Notwithstanding the deadlines in this section, existing and new affected sources must comply with the deadlines for making the initial compliance demonstrations for the BOPF Group mercury emission limit set forth in paragraphs (e)(1) through (4) in this section.

* * * * *

■ 10. Revise § 63.7821 to read as follows:

§ 63.7821 When must I conduct subsequent performance tests?

(a) You must conduct subsequent performance tests to demonstrate compliance with all applicable emission and opacity limits in table 1 to this subpart at the frequencies specified in paragraphs (b) through (m) of this section.

(b) For each sinter cooler at an existing sinter plant and each emissions unit equipped with a control device other than a baghouse, you must conduct subsequent particulate matter and opacity performance tests no less frequently than twice (at mid-term and renewal) during each term of your title V operating permit.

(c) For each emissions unit equipped with a baghouse, you must conduct subsequent particulate matter and opacity performance tests no less frequently than once during each term of your title V operating permit.

(d) For sources without a title V operating permit, you must conduct subsequent particulate matter and opacity performance tests every 2.5 years.

(e) For each BOPF Group, if demonstrating compliance with the mercury emission limit in table 1 to this subpart through performance testing under §§ 63.7825 and 63.7833, you must conduct subsequent performance tests twice per permit cycle (*i.e.,* mid-term and initial/final) for sources with title V operating permits, and every 2.5 years for sources without a title V operating permit, at the outlet of the control devices for the BOPF Group.

(f) For each sinter plant windbox, you must conduct subsequent mercury, hydrogen chloride, carbonyl sulfide, dioxin/furan, and polycyclic aromatic hydrocarbon performance tests every 5 years.

(g) For each blast furnace stove and BOPF shop primary emission control device, you must conduct subsequent hydrogen chloride and total hydrocarbon testing every 5 years. For the BOPF shop primary emission control device, you must also conduct subsequent dioxin/furan testing every 5 years.

(h) For each blast furnace casthouse and BOPF shop, you must conduct subsequent opacity tests two times per month during a cast, or during a full heat cycle, as appropriate.

(i) For planned bleeder valve openings on each blast furnace, you must conduct opacity tests according to § 63.7823(f) for each planned opening.

(j) For slag processing, handling, and storage operations for each blast furnace or BOPF, you must conduct subsequent opacity tests once per week for a minimum of 18 minutes for each: BF pit filling; BOPF slag pit filling; BF pit digging; BOPF slag pit digging; and one slag handling (either truck loading or dumping slag to slag piles).

(k) For large bells on each blast furnace, you must conduct visible emissions testing on the interbell relief valve according to EPA Method 22 in appendix A–7 to part 60 of this chapter, unless specified in paragraphs (k)(1) through (3) of this section. Testing must be conducted monthly, for 15 minutes.

(1) If visible emissions are detected for a large bell during the monthly visible emissions testing, you must conduct EPA Method 9 (in appendix A–4 to part 60 of this chapter) opacity tests in place of EPA Method 22 testing on that bell once per month, taking 3-minute averages for 15 minutes, until the large bell seal is repaired or replaced.

(2) If the average of 3 instantaneous visible emission readings taken while the interbell relief valve is exhausting exceeds 20 percent, you must initiate corrective action within five business days.

(3) Ten business days after the initial opacity exceedance of 20 percent, you must conduct an EPA Method 9 opacity test, taking 3-minute averages for 15 minutes. If the average of 3 instantaneous visible emissions readings from this test exceeds 20 percent, you must repair or replace that bell seal within 4 months.

(l) For small bells on each blast furnace, you must conduct visible emissions testing according to EPA Method 22 in appendix A–7 to part 60 of this chapter. Testing must be conducted monthly for 15 minutes. If visible emissions are observed, you must compare the period between the visible emissions being present and the most recent bell seal repair or replacement. If this time period or throughput is shorter or lower than the period or throughput stated in the O&M plan required by 63.7800, this new shorter period or lower limit shall be placed in the O&M plan as the work practice limit.

(m) For each blast furnace casthouse, you must conduct subsequent hydrogen chloride and total hydrocarbon testing every 5 years.

■ 11. Amend § 63.7823 by revising paragraph (a) and adding paragraphs (c)(3), (d)(6), and (f) through (h) to read as follows:

§ 63.7823 What test methods and other procedures must I use to demonstrate initial compliance with the opacity limits?

(a) For each discharge end of a sinter plant, sinter plant cooler, blast furnace casthouse, BOPF shop, and large bell on a blast furnace, you must conduct each performance test that applies to your affected source based on representative performance (*i.e.,* performance based on normal operating conditions) of the affected source for the period being tested, according to the conditions detailed in paragraphs (b) through (d) of this section. Representative conditions exclude periods of startup and shutdown. You shall 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 such conditions represent normal operation. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

* * * * *

(c) * * *

(3) For the blast furnace casthouse, make observations at each opening:

(i) If EPA Method 9 is used, observations should be made separately at each opening.

(ii) If ASTM D7520–16 (incorporated by reference, see § 63.14) is used, observations may be read for more than one opening at the same time.

(d) * * *

(6) Make observations at each opening:

(i) If EPA Method 9 in appendix A–4 to part 60 of this chapter is used, observations should be made separately at each opening.

(ii) If ASTM D7520–16 (incorporated by reference, see § 63.14) is used, observations may be read for more than one opening at the same time.

* * * * *

(f) To determine compliance with the applicable opacity limit in table 1 to this subpart for planned bleeder valve openings at a blast furnace:

(1) Using a certified observer, determine the opacity of emissions according to EPA Method 9 in appendix A–4 to part 60 of this chapter. Alternatively, ASTM D7520–16 (incorporated by reference, see § 63.14) may be used with the following conditions:

(i) During the DCOT certification procedure outlined in Section 9.2 of ASTM D7520–16 (incorporated by reference, see § 63.14), the owner or operator or the DCOT vendor must be present the plumes in front of various backgrounds of color and contrast representing conditions anticipated during field use such as blue sky, trees, and mixed backgrounds (clouds and/or a sparse tree stand).

(ii) The owner or operator must also have standard operating procedures in place including daily or other frequency quality checks to ensure the equipment is within manufacturing specifications as outlined in Section 8.1 of ASTM D7520–16 (incorporated by reference, see § 63.14).

(iii) The owner or operator must follow the recordkeeping procedures outlined in § 63.10(b)(1) for the DCOT certification, compliance report, data sheets, and all raw unaltered JPEGs used for opacity and certification determination.

(iv) The owner or operator or the DCOT vendor must have a minimum of four independent technology users apply the software to determine the visible opacity of the 300 certification plumes. For each set of 25 plumes, the user may not exceed 15-percent opacity of any one reading and the average error must not exceed 7.5-percent opacity.

(v) Use of this approved alternative does not provide or imply a certification or validation of any vendor's hardware or software. The onus to maintain and verify the certification and/or training of the DCOT camera, software, and operator in accordance with ASTM D7520–16 (incorporated by reference, see § 63.14) and these requirements is on the facility, DCOT operator, and DCOT vendor.

(2) Conduct opacity observations in 6-minute block averages starting as soon as event begins or sunrise whichever is later and ending either when the bleeder valve closes, sunset, or after the first 6-minute block average where all readings are zero percent opacity, but in no case shall the opacity observation period be less than 6 minutes.

(g) To determine compliance with the applicable opacity limit in table 1 to this subpart for slag processing, handling, and storage operations for a blast furnace or BOPF:

(1) Using a certified observer, determine the opacity of emissions according to EPA Method 9 in appendix A–4 to part 60 of this chapter.

(2) Conduct opacity observations in 6-minute blocks for 30 minutes at each: slag dumping to BF pit; BOPF slag dumping to pit; BF pit digging, BOPF pit digging; slag dumping to a pile, slag

dumping to a piece of slag handling equipment such as crusher.

(h) To determine compliance with the work practice trigger for large bells on a blast furnace:

(1) Using a certified observer, determine the opacity of emissions according to EPA Method 9 in appendix A–4 to part 60 of this chapter.

(2) Conduct opacity observations of 15 instantaneous interbell relief valve emissions.

■ 12. Amend § 63.7825 by:

■ a. Revising the section heading, paragraph (a) introductory text, and paragraphs (b)(1)(v), (b)(2), and (c); and

■ b. Adding paragraphs (g) through (k).

The revisions and additions read as follows:

§ 63.7825 What test methods and other procedures must I use to demonstrate initial compliance with the emission limits for hazardous air pollutants?

(a) If demonstrating compliance with the emission limits in Table 1 to this subpart through performance testing, you must conduct a performance test to demonstrate initial compliance with the emission limit. If demonstrating compliance with the emission limit through performance testing, you must conduct each performance test that applies to your affected source based on representative performance (*i.e.,* performance based on normal operating conditions) of the affected source for the period being tested, according to the conditions detailed in paragraphs (b) through (k) of this section. Representative conditions exclude periods of startup and shutdown. You shall not conduct performance tests during periods of malfunction. Initial compliance tests must be conducted by the deadlines in § 63.7820(e).

* * * * *

(b) * * *

(1) * * *

(v) EPA Method 29 or 30B in appendix A–8 to part 60 of this chapter to determine the concentration of mercury from the exhaust stream stack of each unit. If performing measurements using EPA Method 29, you must collect a minimum sample volume of 1.7 dscm (60 dscf). Alternative test methods may be considered on a case-by-case basis per § 63.7(f).

(2) Three valid test runs are needed to comprise a performance test of each unit in table 1 to this subpart as applicable. If the performance testing results for any of the emission points yields a non-detect value, then the method detection limit (MDL) must be used to calculate the mass emissions (lb) for that emission unit and, in turn, for calculating the sum of the emissions (in units of pounds of mercury per ton of steel scrap or pounds of mercury per ton of product sinter) for all units subject to the emission standard for determining compliance. If the resulting mercury emissions are greater than the MACT emission standard, the owner or operator may use procedures that produce lower MDL results and repeat the mercury performance testing one additional time for any emission point for which the measured result was below the MDL. If this additional testing is performed, the results from that testing must be used to determine compliance (*i.e.,* there are no additional opportunities allowed to lower the MDL).

* * * * *

(c) Calculate the mass emissions, based on the average of three test run values, for each BOPF Group unit (or combination of units that are ducted to a common stack and are tested when all affected sources are operating pursuant to paragraph (a) of this section) using equation 1 to this paragraph (c) as follows:

Equation 1 to paragraph (c)

$$E = \frac{C_S \times Q \times t}{454{,}000 \times 35.31} \quad \text{(Eq. 1)}$$

Where:

E = Mass emissions of pollutant, pounds (lb);
C_s = Concentration of pollutant in stack gas, mg/dscm;
454,000 = Conversion factor (mg/lb);
Q = Volumetric flow rate of stack gas, dscf/min;
35.31 = Conversion factor (dscf/dscm); and
t = Duration of test, minutes.

* * * * *

(g) To demonstrate compliance with the emission limit for hydrogen chloride in table 1 to this subpart through performance testing, follow the test methods and procedures in paragraphs (g)(1) through (3) of this section.

(1) Determine the concentration of hydrogen chloride according to the following test methods:

(i) The methods specified in paragraphs (b)(1)(i) through (iv) of this section, and

(ii) EPA Method 26A in appendix A–8 to part 60 of this chapter to determine the concentration of hydrogen chloride from the exhaust stream stack of each unit, with the following conditions; or

(A) Collect a minimum sample volume of 70 dscf (2 dscm) of gas during each run.

(B) [Reserved]

(iii) EPA Method 320 in appendix A to this part to determine the concentration of hydrogen chloride and hydrogen fluoride from the exhaust stream stack of each unit. Alternatively, ASTM D6348–12(R2020), (incorporated by reference, see § 63.14) may be used with the following conditions:

(A) The test plan preparation and implementation in the Annexes to ASTM D 6348–12(R2020), Annexes A1 through A8 are mandatory; and

(B) In ASTM D6348–12(R2020) 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 equation 2 o to this paragraph (g)(1)(iii)(B) as follows:

Equation 2 to paragraph (g)(1)(iii)(B)

$$Reported\ Results = \frac{c_s}{\%R} \times 100 \quad \text{(Eq. 2)}$$

Where

c_s = measured concentration in stack.

(2) At least three valid test runs are needed to comprise a performance test of each unit in table 1 to this subpart. If the performance testing results for any of the emission points yields a non-detect value, then the MDL must be used to calculate the mass emissions (lb) for that unit and, in turn, for calculating the emissions rate (lb/ton of product sinter, lb/ton of iron, or lb/ton of steel).

(3) Calculate the emissions from each new and existing affected source in pounds of hydrogen chloride per ton of throughput processed or unit of energy (tons of product sinter, tons of iron, tons of steel, or MMBtu) to determine initial compliance with the emission limits in table 1 to this subpart.

(h) To demonstrate compliance with the emission limit for carbonyl sulfide in table 1 to this subpart through performance testing, follow the test methods and procedures in paragraphs (h)(1) through (3) of this section.

(1) Determine the concentration of carbonyl sulfide according to the following test methods:

(i) The methods specified in paragraphs (b)(1)(i) through (iv) of this section, and

(ii) EPA Method 15 in appendix A–5 to part 60 of this chapter to determine the concentration of carbonyl sulfide from the exhaust stream stack of each unit; or

(iii) EPA Method 320 in appendix A to this part to determine the concentration of carbon disulfide and carbonyl sulfide from the exhaust stream stack of each unit. Alternatively, ASTM D6348–12 (R2020), (incorporated by reference, see § 63.14) may be used with the following conditions:

(A) The test plan preparation and implementation in the Annexes to ASTM D 6348–12 (R2020), Annexes A1 through A8 are mandatory; and

(B) In ASTM D6348–12 (R2020) 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 Equation 2 of this section.

(2) Three valid test runs at least one hour in duration are needed to comprise a performance test of each unit in table 1 to this subpart. If the performance testing results for any of the emission points yields a non-detect value, then the MDL must be used to calculate the mass emissions (lb) for that unit and, in turn, for calculating the emissions rate (lb/ton of product sinter).

(3) Calculate the emissions from each new and existing affected source in pounds of carbonyl sulfide per ton of product sinter to determine initial compliance with the emission limits in table 1 to this subpart .

(i) To demonstrate compliance with the emission limit for total hydrocarbons in table 1 to this subpart through performance testing, follow the test methods and procedures in paragraphs (i)(1) through (5) of this section.

(1) Determine the concentration of total hydrocarbons according to the following test methods:

(i) The methods specified in paragraphs (b)(1)(i) through (iv) of this section, and

(ii) EPA Method 25A in appendix A–7 to part 60 of this chapter to determine the concentration of total hydrocarbons as propane from the exhaust stream stack of each unit.

(2) Three valid test runs at least one hour in duration are needed to comprise a performance test of each unit in table 1 to this subpart. If the performance testing results for any of the emission points yields a non-detect value, then the MDL must be used to calculate the mass emissions (lb) for that unit and, in turn, for calculating the emissions rate (lb/ton of iron or lb/ton of steel).

(3) For BOPF tests, the test runs must include at least one full production cycle (from scrap charge to 3 minutes after slag is emptied from the vessel) for each run, except for BOPF with closed hood systems, where sampling should be performed only during the primary oxygen blow and only for 20 heat cycles.

(4) For blast furnaces, each test run duration must be a minimum of 1 hour.

(5) Calculate the emissions from each new and existing affected source in pounds of total hydrocarbons as propane per ton of throughput processed or unit of energy (tons of iron, tons of steel, or MMBtu) to determine initial compliance with the emission limits in table 1 to this subpart.

(j) To demonstrate compliance with the emission limit for D/F TEQ in table 1 to this subpart through performance testing, follow the test methods and procedures in paragraphs (j)(1) through (4) of this section.

(1) Determine the concentration of each dioxin and furan listed in table 5 to this subpart according to the following test methods:

(i) The methods specified in paragraphs (b)(1)(i) through (iv) of this section, and

(ii) EPA Method 23 in appendix A–7 to part 60 of this chapter to determine the concentration of each dioxin and furan listed in table 5 to this subpart from the exhaust stream stack of each unit. You must collect a minimum sample volume of 105 dscf (3 dscm) of gas during each test run.

(2) Three valid test runs are needed to comprise a performance test of each unit in table 1 to this subpart. For determination of TEQ, zero may be used in subsequent calculations for values less than the estimated detection limit (EDL). For estimated maximum pollutant concentration (EMPC) results, when the value is greater than the EDL, the EMPC value must be used in determination of TEQ, when the EMPC is less than the EDL, zero may be used.

(3) For BOPF tests, the test runs must include at least one full production cycle (from scrap charge to 3 minutes after slag is emptied from the vessel) for each run, except for BOPF with closed hood systems, where sampling should be performed only during the primary oxygen blow and only for 20 heat cycles or the collection of 105 dscf (3 dscm) sample volume, whichever is less.

(4) Calculate the sum of the D/F TEQ per ton of throughput processed (tons of product sinter or tons of steel) to determine initial compliance with the emission limits in table 1 using equation 3 to this paragraph (j)(4) as follows:

Equation 3 to paragraph (j)(4)

$$TEQ = \frac{\sum_{i=1}^{n}(M_i \times TEF_i)}{T_r \times P} \text{ (Eq. 3)}$$

Where:

TEQ = sum of the 2,3,7,8-TCDD TEQs, lb/ton of throughput processed
M_i = mass of dioxin or furan cogener i during performance test run, lbs
TEF_i = 2,3,7,8-TCDD toxic equivalency factor (TEF) for cogener i, as provided in Table 5 of this subpart
n = number of cogeners included in TEQ
T_r = time of performance test run, hours
P = production rate during performance test run, tons of throughput processed per hour.

(k) To demonstrate compliance with the emission limit for polycyclic aromatic hydrocarbons in table 1 to this subpart through performance testing, follow the test methods and procedures in paragraphs (k)(1) through (3) of this section.

(1) Determine the concentration of each polycyclic aromatic hydrocarbon listed in table 6 to this subpart according to the following test methods:

(i) The methods specified in paragraphs (b)(1)(i) through (iv) of this section, and

(ii) EPA Method 23 in appendix A–7 to part 60 of this chapter to determine the concentration of each polycyclic aromatic hydrocarbon listed in table 6 to this subpart from the exhaust stream stack of each unit. You must collect a minimum sample volume of 105 dscf (3 dscm) of gas during each test run.

(2) Three valid test runs are needed to comprise a performance test of each unit in table 1 to this subpart. If the performance testing results for any of the emission points yields a non-detect value, then the EDL must be used to calculate the mass emissions (lb) for that unit and, in turn, for calculating the emissions rate (lb/ton of product sinter).

(3) Calculate the sum of polycyclic aromatic hydrocarbons per ton of product sinter to determine initial compliance with the emission limits in table 1 to this subpart using equation 4 to this paragraph (k)(3) as follows:

Equation 4 to paragraph (k)(3)

$$E = \frac{\sum_{i=1}^{n} M_i}{T_r \times P} \text{ (Eq. 4)}$$

Where:

E = emission rate of polycyclic aromatic hydrocarbons, lb/ton of sinter
M_i = mass of polycyclic aromatic hydrocarbon i, as provided in Table 6 to this subpart, during performance test run, lbs
n = number of polycyclic aromatic hydrocarbons included in emissions
T_r = time of performance test run, hours
P = production rate during performance test run, tons of product sinter per hour.

■ 13. Amend § 63.7830 by revising paragraph (e)(2) to read as follows:

§ 63.7830 What are my monitoring requirements?

* * * * *

(e) * * *

(2) Compute and record the 30-day rolling average of the volatile organic compound emissions (lbs/ton of sinter) for each operating day using the procedures in § 63.7824(e).

■ 14. Amend § 63.7833 by adding paragraph (j) to read as follows:

§ 63.7833 How do I demonstrate continuous compliance with the emission limitations that apply to me?

* * * * *

* * * * *

(j) For large bells on each blast furnace, you must demonstrate continuous compliance by following the requirements specified in paragraphs (j)(1) and (2) of this section if a bell seal exceeds a 20 percent average of 3 instantaneous opacity readings of the interbell relief valve emissions.

(1) Initiate corrective action within five business days.

(2) Ten business days after the initial opacity exceedance of 20 percent, if the average of 3 instantaneous visible emissions readings from this test exceeds 20 percent, you must repair or replace that bell seal within 4 months.

■ 15. Amend § 63.7840 by removing paragraphs (g)(3) and (h)(3) and adding paragraph (i).

The addition reads as follows:

§ 63.7840 What notifications must I submit and when?

* * * * *

(i) Confidential business information (CBI): For notifications and reports required to be submitted to CEDRI:

(1) The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (h) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA.

(2) The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website.

(3) Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

(4) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described above, should include clear CBI markings and be flagged to the attention of the Group Leader, Measurement Policy Group. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(5) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection

Agency, Research Triangle Park, North Carolina 27711, Attention Group Leader, Measurement Policy Group. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(6) All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(7) You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described in paragraphs (g) or (h) of this section.

■ 16. Amend § 63.7841 by adding paragraph (b)(14), revising paragraph (d), and adding paragraph (h) to read as follows:

§ 63.7841 What reports must I submit and when?

* * * * *

(b) * * *

(14) For each unplanned bleeder valve opening for each blast furnace, you must include the information in paragraphs (b)(14)(i) through (iii) of this section.

(i) The date and time of the event.

(ii) The duration of the event.

(iii) Any corrective actions taken in response to the event.

* * * * *

(d) *CEDRI submission.* If you are required to submit reports following the procedure specified in this paragraph, you must submit reports to the EPA via CEDRI, which can be accessed through EPA's CDX (*https://cdx.epa.gov/*). You must use the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/compliance-and-emissions-data-reporting-interface-cedri*) for this subpart. The date report templates become available will be listed on the CEDRI website. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report, you must submit a complete file, including information claimed to be CBI, to the EPA following the procedures in paragraphs (d)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described above, should include clear CBI markings and be flagged to the attention of the Integrated Iron and Steel Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Integrated Iron and Steel Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

* * * * *

(h) *Fenceline monitoring reports.* For fenceline monitoring systems subject to § 63.7792, each owner or operator must submit Fenceline Monitoring Reports on a quarterly basis using the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart and following the procedure specified in paragraph (d) of this section. The first quarterly report must be submitted once the owner or operator has obtained 12 months of data. The first quarterly report must cover the period beginning on the date one year after the promulgation of the metals fenceline method and ending on March 31, June 30, September 30 or December 31, whichever date is the first date that occurs after the owner or operator has obtained 12 months of data (*i.e.,* the first quarterly report will contain between 12 and 15 months of data). Each subsequent quarterly report must cover one of the following reporting periods: Quarter 1 from January 1 through March 31; Quarter 2 from April 1 through June 30; Quarter 3 from July 1 through September 30; and Quarter 4 from October 1 through December 31. Each quarterly report must be electronically submitted no later than 45 calendar days following the end of the reporting period.

(1) Facility name and address.

(2) Year and reporting quarter (*i.e.,* Quarter 1, Quarter 2, Quarter 3, or Quarter 4).

(3) For each sampler: The latitude and longitude location coordinates; the sampler name; and identification of the type of sampler (*e.g.,* regular monitor, extra monitor, duplicate, field blank, inactive). Coordinates shall be in decimal degrees with at least five decimal places.

(4) The beginning and ending dates for each sampling period.

(5) Individual sample results for each monitored compound, reported in units of $\mu g/m^3$, for each monitor for each sampling period that ends during the reporting period. Results below the method detection limit shall be flagged as below the detection limit and reported at the method detection limit.

(6) Data flags for each outlier determined in accordance with the fenceline metals method. For each outlier, the owner or operator must submit the individual sample result of the outlier, as well as the evidence used to conclude that the result is an outlier.

(7) The biweekly concentration difference (Δc) for each sampling period and the annual average Δc for each sampling period.

(8) Indication of whether the owner or operator was required to develop a corrective action plan under § 63.7792(e).

■ 17. Amend § 63.7842 by revising paragraph (d) and adding paragraphs (f) and (g) to read as follows.

§ 63.7842 What records must I keep?

* * * * *

(d) You must keep the records required in §§ 63.7823, 63.7833, and 63.7834 to show continuous compliance with each emission limitation and operation and maintenance requirement that applies to you. This includes a record of each large and small bell repair and replacement, a record of the date on which the large bell opacity has exceeded 20 percent, and the most current time period or throughput over which no opacity was observed from the small bell.

* * * * *

(f) For fenceline monitoring systems subject to § 63.7792 of this subpart, each owner or operator must keep the records specified in paragraphs (f)(1) through (11) of this section.

(1) Coordinates of samplers, including co-located 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.

(2) The start and stop times and dates for each sample, as well as the sample identifying information.

(3) Sampling period average temperature and barometric pressure measurements.

(4) For each outlier determined in accordance with the procedures specified in the fenceline metals method, the sampler location and the concentration of the outlier and the evidence used to conclude that the result is an outlier.

(5) For samples that will be adjusted for uniform background, the location of and the concentration measured simultaneously by the background sampler, and the perimeter samplers to which it applies.

(6) Individual sample results, the calculated Δc 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.

(7) Method detection limit for each sample, including co-located samples and blanks.

(8) Documentation of the root cause analysis and any resulting corrective action taken each time an action level is exceeded, including the dates the root cause analysis was initiated and the resulting correction action(s) were taken.

(9) Any corrective action plan developed under § 63.7792(e).

(10) Other records as required by the sampling method.

(11) If a near-field source correction is used as provided in § 63.7792(f), or if an alternative test method is used that provides time-resolved measurements, 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.

(g) For each unplanned bleeder valve opening for each blast furnace, you must keep the records specified in paragraphs (g)(1) through (3) of this section.

(1) The start date and start time of the event.

(2) The duration of the event in minutes.

(3) Any corrective actions taken in response to the event.

■ 18. Amend § 63.7852 by adding definitions for ‘‘Iron beaching operation’’, Large blast furnace’’, ‘‘Planned bleeder valve opening’’, ‘‘Slip’’, ‘‘Small blast furnace’’, ‘‘Total hydrocarbons (THC)’’, and ‘‘Unplanned bleeder valve opening’’ to read as follows:

§ 63.7852 What definitions apply to this subpart?

* * * * *

Iron beaching operation means pouring hot molten iron from a torpedo car onto the ground when the iron from the blast furnace cannot be charged to the basic oxygen process furnace.

* * * * *

Large blast furnace means a blast furnace with a working volume of greater than 2,500 m^3.

* * * * *

Planned bleeder valve opening means the opening of a blast furnace pressure relief safety valve that is initiated by an operator.

* * * * *

Slip means when raw materials loaded in the top of the furnace fail to descend smoothly in the furnace and bind together to form a ‘‘bridge’’ which than ‘‘hangs’’ (*i.e.,* accumulates) in one position in the furnace. When a ‘‘hang’’ eventually falls, or ‘‘slips,’’ it creates a pressure surge that may open the bleeder valves, releasing emissions in the form of a large dust cloud.

Small blast furnace means a blast furnace with a working volume of less than 2,500 m^3.

* * * * *

Total hydrocarbons (THC) means the sum of organic compounds measured as carbon using EPA Method 25A (appendix A–7 to part 60 of this chapter).

Unplanned bleeder valve opening means the opening of a blast furnace pressure relief safety valve that is not a planned bleeder valve opening.

* * * * *

■ 19. Revise tables 1 through 4 to subpart FFFFF to read as follows:

Table 1 to Subpart FFFFF of Part 63—Emission, Opacity, and Work Practice Limits

As required in § 63.7790(a), you must comply with each applicable emission, opacity, and work practice limit in the following table:

For . . .	You must comply with each of the following . . .
1. Each windbox exhaust stream at an existing sinter plant.	a. You must not cause to be discharged to the atmosphere any gases that contain particulate matter in excess of 0.4 lb/ton of product sinter; b. You must not cause to be discharged to the atmosphere any gases that contain mercury in excess of 0.000018 lb/ton of product sinter; c. You must not cause to be discharged to the atmosphere any gases that contain hydrogen chloride in excess of 0.025 lb/ton of product sinter; d. You must not cause to be discharged to the atmosphere any gases that contain carbonyl sulfide in excess of 0.064 lb/ton of product sinter; e. You must not cause to be discharged to the atmosphere any gases that contain D/F TEQs in excess of 1.1E–08 lb/ton of product sinter; and f. You must not cause to be discharged to the atmosphere any gases that contain polycyclic aromatic hydrocarbons in excess of 0.0018 lb/ton of product sinter.
2. Each windbox exhaust stream at a new sinter plant.	a. You must not cause to be discharged to the atmosphere any gases that contain particulate matter in excess of 0.3 lb/ton of product sinter; b. You must not cause to be discharged to the atmosphere any gases that contain mercury in excess of 0.000012 lb/ton of product sinter; c. You must not cause to be discharged to the atmosphere any gases that contain hydrogen chloride in excess of 0.0012 lb/ton of product sinter; d. You must not cause to be discharged to the atmosphere any gases that contain carbonyl sulfide in excess of 0.030 lb/ton of product sinter; e. You must not cause to be discharged to the atmosphere any gases that contain D/F TEQs in excess of 1.1E–08 lb/ton of product sinter; and

For . . .	You must comply with each of the following . . .
	f. You must not cause to be discharged to the atmosphere any gases that contain polycyclic aromatic hydrocarbons in excess of 0.0015 lb/ton of product sinter.
3. Each discharge end at an existing sinter plant.	a. You must not cause to be discharged to the atmosphere any gases that exit from one or more control devices that contain, on a flow-weighted basis, particulate matter in excess of 0.02 gr/dscf;[1,2] and b. You must not cause to be discharged to the atmosphere any secondary emissions that exit any opening in the building or structure housing the discharge end that exhibit opacity greater than 20 percent (6-minute average).
4. Each discharge end at a new sinter plant.	a. You must not cause to be discharged to the atmosphere any gases that exit from one or more control devices that contain, on a flow weighted basis, particulate matter in excess of 0.01 gr/dscf; and b. You must not cause to be discharged to the atmosphere any secondary emissions that exit any opening in the building or structure housing the discharge end that exhibit opacity greater than 10 percent (6-minute average).
5. Each sinter cooler at an existing sinter plant.	You must not cause to be discharged to the atmosphere any emissions that exhibit opacity greater than 10 percent (6-minute average).
6. Each sinter cooler at a new sinter plant.	You must not cause to be discharged to the atmosphere any gases that contain particulate matter in excess of 0.01 gr/dscf.
7. Each casthouse at an existing blast furnace.	a. You must not cause to be discharged to the atmosphere any gases that exit from a control device that contain particulate matter in excess of 0.01 gr/dscf;[2] b. You must not cause to be discharged to the atmosphere any secondary emissions that exit all openings in the casthouse or structure housing the blast furnace that exhibit opacity greater than 20 percent (6-minute average); c. You must not cause to be discharged to the atmosphere any gases that exit from a control device that contain hydrogen chloride in excess of 0.0056 lb/ton of iron; d. You must not cause to be discharged to the atmosphere any gases that exit from a control device that contain total hydrocarbons as propane in excess of 0.48 lb/ton of iron; and e. You must not cause unplanned bleeder valve openings in excess of 4 events per year for large blast furnaces or 15 events per year for small blast furnaces.
8. Each casthouse at a new blast furnace.	a. You must not cause to be discharged to the atmosphere any gases that exit from a control device that contain particulate matter in excess of 0.003 gr/dscf; and b. You must not cause to be discharged to the atmosphere any secondary emissions that exit all openings in the casthouse or structure housing the blast furnace that exhibit opacity greater than 15 percent (6-minute average); c. You must not cause to be discharged to the atmosphere any gases that exit from a control device that contain hydrogen chloride in excess of 0.00059 lb/ton of iron; d. You must not cause to be discharged to the atmosphere any gases that exit from a control device that contain total hydrocarbons as propane in excess of 0.035 lb/ton of iron; and e. You must not cause unplanned bleeder valve openings in excess of zero events per year.
9. Each BOPF at a new or existing shop	a. You must not cause to be discharged to the atmosphere any gases that exit from a primary emission control system for a BOPF with a closed hood system at a new or existing BOPF shop that contain, on a flow-weighted basis, particulate matter in excess of 0.03 gr/dscf during the primary oxygen blow;[2,3] b. You must not cause to be discharged to the atmosphere any gases that exit from a primary emission control system for a BOPF with an open hood system that contain, on a flow-weighted basis, particulate matter in excess of 0.02 gr/dscf during the steel production cycle for an existing BOPF shop[2,3] or 0.01 gr/dscf during the steel production cycle for a new BOPF shop;[3] c. You must not cause to be discharged to the atmosphere any gases that exit from a control device used solely for the collection of secondary emissions from the BOPF that contain particulate matter in excess of 0.01 gr/dscf for an existing BOPF shop[2] or 0.0052 gr/dscf for a new BOPF shop; d. You must not cause to be discharged to the atmosphere any gases that exit from a primary emission control system for a BOPF that contain hydrogen chloride in excess of 0.058 lb/ton of steel for existing sources and 2.8E–04 lb/ton steel for new sources; e. You must not cause to be discharged to the atmosphere any gases that exit from a primary emission control system for a BOPF that contain THC as propane in excess of 0.04 lb/ton of steel for existing sources and 0.0017 lb/ton of steel for new sources; and f. You must not cause to be discharged to the atmosphere any gases that exit from a primary emission control system for a BOPF that contain D/F TEQs in excess of 9.2E–10 lb/ton of steel.
10. Each hot metal transfer, skimming, and desulfurization operation at a new or existing BOPF shop.	You must not cause to be discharged to the atmosphere any gases that exit from a control device that contain particulate matter in excess of 0.01 gr/dscf for an existing BOPF shop[2] or 0.003 gr/dscf for a new BOPF shop.
11. Each ladle metallurgy operation at a new or existing BOPF shop.	You must not cause to be discharged to the atmosphere any gases that exit from a control device that contain particulate matter in excess of 0.01 gr/dscf for an existing BOPF shop[2] or 0.004 gr/dscf for a new BOPF shop.
12. Each existing BOPF shop	You must not cause to be discharged to the atmosphere any secondary emissions that exit any opening in the BOPF shop or any other building housing the BOPF or BOPF shop operation that exhibit opacity greater than 20 percent (3-minute average).
13. Each new BOPF shop	a. You must not cause to be discharged to the atmosphere any secondary emissions that exit any opening in the BOPF shop or other building housing a bottom-blown BOPF or BOPF shop operations that exhibit opacity (for any set of 6-minute averages) greater than 10 percent, except that one 6-minute period not to exceed 20 percent may occur once per steel production cycle; or b. You must not cause to be discharged to the atmosphere any secondary emissions that exit any opening in the BOPF shop or other building housing a top-blown BOPF or BOPF shop operations that exhibit opacity (for any set of 3-minute averages) greater than 10 percent, except that one 3-minute period greater than 10 percent but less than 20 percent may occur once per steel production cycle.
14. Each BOPF Group at an existing BOPF shop.	You must not cause to be discharged to the atmosphere any gases that exit from the collection of BOPF Group control devices that contain mercury in excess of 0.00026 lb/ton of steel scrap input to the BOPF.
15. Each BOPF Group at a new BOPF shop.	You must not cause to be discharged to the atmosphere any gases that exit from the collection of BOPF Group control devices that contain mercury in excess of 0.000081 lb/ton of steel scrap input to the BOPF.
16. Each planned bleeder valve opening at a new or existing blast furnace.	You must not cause to be discharged to the atmosphere any emissions that exhibit opacity greater than 8 percent (6-minute average).
17. Each slag processing, handling and storage operation for a new or existing blast furnace or BOPF.	You must not cause to be discharged to the atmosphere any emissions that exhibit opacity greater than 10 percent (6-minute average).
18. Each existing blast furnace stove	a. You must not cause to be discharged to the atmosphere any gases that exit from a control device that contain HCl in excess of 0.0012 lb/MMBtu; and b. You must not cause to be discharged to the atmosphere any gases that exit from a control device that contain THC in excess of 0.12 lb/MMBtu.
19. Each new blast furnace stove	a. You must not cause to be discharged to the atmosphere any gases that exit from a control device that contain HCl in excess of 4.2e–4 lb/MMBtu; and

For . . .	You must comply with each of the following . . .
	b. You must not cause to be discharged to the atmosphere any gases that exit from a control device that contain THC in excess of 0.0054 lb/MMBtu.

[1] This limit applies if the cooler is vented to the same control device as the discharge end.

[2] This concentration limit (gr/dscf) for a control device does not apply to discharges inside a building or structure housing the discharge end at an existing sinter plant, inside a casthouse at an existing blast furnace, or inside an existing BOPF shop if the control device was installed before August 30, 2005.

[3] This limit applies to control devices operated in parallel for a single BOPF during the oxygen blow.

Table 2 to Subpart FFFFF of Part 63—Initial Compliance With Emission and Opacity Limits

As required in § 63.7826(a)(1), you must demonstrate initial compliance with the emission and opacity limits according to the following table:

For . . .	You have demonstrated initial compliance if . . .
1. Each windbox exhaust stream at an existing sinter plant.	a. The process-weighted mass rate of particulate matter from a windbox exhaust stream, measured according to the performance test procedures in § 63.7822(c), did not exceed 0.4 lb/ton of product sinter; b. The process-weighted mass rate of mercury from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.000018 lb/ton of product sinter; c. The process-weighted mass rate of hydrogen chloride from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.025 lb/ton of product sinter; d. The process-weighted mass rate of carbonyl sulfide from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.064 lb/ton of product sinter; e. The process-weighted mass rate of D/F TEQs from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 1.1E–08 lb/ton of product sinter; and f. The process-weighted mass rate of polycyclic aromatic hydrocarbons from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.0018 lb/ton of product sinter.
2. Each windbox exhaust stream at a new sinter plant.	a. The process-weighted mass rate of particulate matter from a windbox exhaust stream, measured according to the performance test procedures in § 63.7822(c), did not exceed 0.3 lb/ton of product sinter; b. The process-weighted mass rate of mercury from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.000012 lb/ton of product sinter; c. The process-weighted mass rate of hydrogen chloride from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.0012 lb/ton of product sinter; d. The process-weighted mass rate of carbonyl sulfide from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.030 lb/ton of product sinter; e. The process-weighted mass rate of D/F TEQs from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 1.1E–08 lb/ton of product sinter; and f. The process-weighted mass rate of polycyclic aromatic hydrocarbons from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.0015 lb/ton of product sinter.
3. Each discharge end at an existing sinter plant.	a. The flow-weighted average concentration of particulate matter from one or more control devices applied to emissions from a discharge end, measured according to the performance test procedures in § 63.7822(d), did not exceed 0.02 gr/dscf; and b. The opacity of secondary emissions from each discharge end, determined according to the performance test procedures in § 63.7823(c), did not exceed 20 percent (6-minute average).
4. Each discharge end at a new sinter plant.	a. The flow-weighted average concentration of particulate matter from one or more control devices applied to emissions from a discharge end, measured according to the performance test procedures in § 63.7822(d), did not exceed 0.01 gr/dscf; and b. The opacity of secondary emissions from each discharge end, determined according to the performance test procedures in § 63.7823(c), did not exceed 10 percent (6-minute average).
5. Each sinter cooler at an existing sinter plant.	The opacity of emissions, determined according to the performance test procedures in § 63.7823(e), did not exceed 10 percent (6-minute average).
6. Each sinter cooler at a new sinter plant.	The average concentration of particulate matter, measured according to the performance test procedures in § 63.7822(b), did not exceed 0.01 gr/dscf.
7. Each casthouse at an existing blast furnace.	a. The average concentration of particulate matter from a control device applied to emissions from a casthouse, measured according to the performance test procedures in § 63.7822(e), did not exceed 0.01 gr/dscf; b. The opacity of secondary emissions from each casthouse, determined according to the performance test procedures in § 63.7823(c), did not exceed 20 percent (6-minute average); c. The process-weighted mass rate of hydrogen chloride from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.0056 lb/ton of iron; d. The process-weighted mass rate of total hydrocarbons from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.48 lb/ton of iron; and e. The number of unplanned bleeder valve openings in one year, as reported according to the specifications in § 63.7841(b)(14), did not exceed 4 events for large blast furnaces or 15 events for small blast furnaces.
8. Each casthouse at a new blast furnace.	a. The average concentration of particulate matter from a control device applied to emissions from a casthouse, measured according to the performance test procedures in § 63.7822(e), did not exceed 0.003 gr/dscf; and b. The opacity of secondary emissions from each casthouse, determined according to the performance test procedures in § 63.7823(c), did not exceed 15 percent (6-minute average); c. The process-weighted mass rate of hydrogen chloride from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.00059 lb/ton of iron; d. The process-weighted mass rate of total hydrocarbons from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.035 lb/ton of iron; and e. The number of unplanned bleeder valve openings in one year, as reported according to the specifications in § 63.7841(b)(14), did not exceed zero events.
9. Each BOPF at a new or existing BOPF shop.	a. The average concentration of particulate matter from a primary emission control system applied to emissions from a BOPF with a closed hood system, measured according to the performance test procedures in § 63.7822(f), did not exceed 0.03 gr/dscf for a new or existing BOPF shop; b. The average concentration of particulate matter from a primary emission control system applied to emissions from a BOPF with an open hood system, measured according to the performance test procedures in § 63.7822(g), did not exceed 0.02 gr/dscf for an existing BOPF shop or 0.01 gr/dscf for a new BOPF shop;

For . . .	You have demonstrated initial compliance if . . .
	c. The average concentration of particulate matter from a control device applied solely to secondary emissions from a BOPF, measured according to the performance test procedures in § 63.7822(g), did not exceed 0.01 gr/dscf for an existing BOPF shop or 0.0052 gr/dscf for a new BOPF shop; d. The process-weighted mass rate of hydrogen chloride from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.058 lb/ton of steel for an existing BOPF shop or 0.00028 lb/ton of steel for a new BOPF shop; e. The process-weighted mass rate of total hydrocarbons from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.04 lb/ton of steel for an existing BOPF shop or 0.0017 lb/ton of steel for a new BOPF shop; and f. The process-weighted mass rate of D/F TEQs from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 9.2e–10 lb/ton of steel.
10. Each hot metal transfer skimming, and desulfurization at a new or existing BOPF shop.	The average concentration of particulate matter from a control device applied to emissions from hot metal transfer, skimming, or desulfurization, measured according to the performance test procedures in § 63.7822(h), did not exceed 0.01 gr/dscf for an existing BOPF shop or 0.003 gr/dscf for a new BOPF shop.
11. Each ladle metallurgy operation at a new or existing BOPF shop.	The average concentration of particulate matter from a control device applied to emissions from a ladle metallurgy operation, measured according to the performance test procedures in § 63.7822(h), did not exceed 0.01 gr/dscf for an existing BOPF shop or 0.004 gr/dscf for a new BOPF shop.
12. Each existing BOPF shop	The opacity of secondary emissions from each BOPF shop, determined according to the performance test procedures in § 63.7823(d), did not exceed 20 percent (3-minute average).
13. Each new BOPF shop	a. The opacity of the highest set of 6-minute averages from each BOPF shop housing a bottom-blown BOPF, determined according to the performance test procedures in § 63.7823(d), did not exceed 20 percent and the second highest set of 6-minute averages did not exceed 10 percent; or b. The opacity of the highest set of 3-minute averages from each BOPF shop housing a top-blown BOPF, determined according to the performance test procedures in § 63.7823(d), did not exceed 20 percent and the second highest set of 3-minute averages did not exceed 10 percent.
14. Each BOPF Group at an existing BOPF shop.	If demonstrating compliance through performance testing, the average emissions of mercury from the collection of BOPF Group control devices applied to the emissions from the BOPF Group, measured according to the performance test procedures in § 63.7825, did not exceed 0.00026 lb/ton steel scrap input to the BOPF.
15. Each BOPF Group at a new BOPF shop.	If demonstrating compliance through performance testing, the average emissions of mercury from the collection of BOPF Group control devices applied to the emissions from the BOPF Group, measured according to the performance test procedures in § 63.7825, did not exceed 0.000081 lb/ton steel scrap input to the BOPF.
16. Each planned bleeder valve opening at a new or existing blast furnace.	The opacity of emissions, determined according to the performance test procedures in § 63.7823(f), did not exceed 8 percent (6-minute average).
17. Each slag processing, handling and storage operation for a new or existing blast furnace or BOPF.	The opacity of emissions, determined according to the performance test procedures in § 63.7823(g), did not exceed 10 percent (6-minute average).
18. Each existing blast furnace stove	a. The process-weighted mass rate of HCl from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.0012 lb/MMBtu; and b. The process-weighted mass rate of THC from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.12 lb/MMBtu.
19. Each new blast furnace stove	a. The process-weighted mass rate of HCl from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 4.2e–4 lb/MMBtu; and b. The process-weighted mass rate of THC from a windbox exhaust stream, measured according to the performance test procedures in § 63.7825, did not exceed 0.0054 lb/MMBtu.

Table 3 to Subpart FFFFF of Part 63—Continuous Compliance With Emission and Opacity Limits

As required in § 63.7833(a), you must demonstrate continuous compliance with the emission and opacity limits according to the following table:

For . . .	You must demonstrate continuous compliance by . . .
1. Each windbox exhaust stream at an existing sinter plant.	a. Maintaining emissions of particulate matter at or below 0.4 lb/ton of product sinter; b. Conducting subsequent performance tests at the frequencies specified in § 63.7821; c. Maintaining emissions of mercury at or below 0.000018 lb/ton of product sinter; d. Maintaining emissions of hydrogen chloride at or below 0.025 lb/ton of product sinter; e. Maintaining emissions of carbonyl sulfide at or below 0.064 lb/ton of product sinter; f. Maintaining emissions of D/F TEQs at or below 1.1E–08 lb/ton of product sinter; and g. Maintaining emissions of polycyclic aromatic hydrocarbons at or below 0.0018 lb/ton of product sinter.
2. Each windbox exhaust stream at a new sinter plant.	a. Maintaining emissions of particulate matter at or below 0.3 lb/ton of product sinter; b. Conducting subsequent performance tests at the frequencies specified in § 63.7821; c. Maintaining emissions of mercury at or below 0.000012 lb/ton of product sinter; d. Maintaining emissions of hydrogen chloride at or below 0.0012 lb/ton of product sinter; e. Maintaining emissions of carbonyl sulfide at or below 0.030 lb/ton of product sinter; f. Maintaining emissions of D/F TEQs at or below 1.1E–08 lb/ton of product sinter; and g. Maintaining emissions of polycyclic aromatic hydrocarbons at or below 0.0015 lb/ton of product sinter.
3. Each discharge end at an existing sinter plant.	a. Maintaining emissions of particulate matter from one or more control devices at or below 0.02 gr/dscf; and b. Maintaining the opacity of secondary emissions that exit any opening in the building or structure housing the discharge end at or below 20 percent (6-minute average); and c. Conducting subsequent performance tests at the frequencies specified in § 63.7821.
4. Each discharge end at a new sinter plant.	a. Maintaining emissions of particulate matter from one or more control devices at or below 0.01 gr/dscf; and b. Maintaining the opacity of secondary emissions that exit any opening in the building or structure housing the discharge end at or below 10 percent (6-minute average); and c. Conducting subsequent performance tests at the frequencies specified in § 63.7821.
5. Each sinter cooler at an existing sinter plant.	a. Maintaining the opacity of emissions that exit any sinter cooler at or below 10 percent (6-minute average); and b. Conducting subsequent performance tests at the frequencies specified in § 63.7821.
6. Each sinter cooler at a new sinter plant.	a. Maintaining emissions of particulate matter at or below 0.1 gr/dscf; and

For . . .	You must demonstrate continuous compliance by . . .
	b. Conducting subsequent performance tests at the frequencies specified in § 63.7821.
7. Each casthouse at an existing blast furnace.	a. Maintaining emissions of particulate matter from a control device at or below 0.01 gr/dscf; b. Maintaining the opacity of secondary emissions that exit all openings in the casthouse or structure housing the casthouse at or below 20 percent (6-minute average); c. Conducting subsequent performance tests at the frequencies specified in § 63.7821; d. Maintaining emissions of hydrogen chloride at or below 0.0056 lb/ton of iron; e. Maintaining emissions of total hydrocarbons at or below 0.48 lb/ton of iron; and f. Maintaining unplanned bleeder valve openings at or below 4 events per year for large blast furnaces or 15 events per year for small blast furnaces.
8. Each casthouse at a new blast furnace.	a. Maintaining emissions of particulate matter from a control device at or below 0.003 gr/dscf; b. Maintaining the opacity of secondary emissions that exit all openings in the casthouse or structure housing the casthouse at or below 15 percent (6-minute average); c. Conducting subsequent performance tests at the frequencies specified in § 63.7821; d. Maintaining emissions of hydrogen chloride at or below 0.00059 lb/ton of iron; e. Maintaining emissions of total hydrocarbons at or below 0.035 lb/ton of iron; and f. Maintaining unplanned bleeder valve openings at zero events per year.
9. Each BOPF at a new or existing BOPF shop.	a. Maintaining emissions of particulate matter from the primary control system for a BOPF with a closed hood system at or below 0.03 gr/dscf; b. Maintaining emissions of particulate matter from the primary control system for a BOPF with an open hood system at or below 0.02 gr/dscf for an existing BOPF shop or 0.01 gr/dscf for a new BOPF shop; c. Maintaining emissions of particulate matter from a control device applied solely to secondary emissions from a BOPF at or below 0.01 gr/dscf for an existing BOPF shop or 0.0052 gr/dscf for a new BOPF shop; d. Conducting subsequent performance tests at the frequencies specified in § 63.7821; e. Maintaining emissions of hydrogen chloride from a primary emission control system for a BOPF at or below 0.058 lb/ton of steel for existing sources and 2.8E–04 lb/ton steel for new sources; f. Maintaining emissions of THC from a primary emission control system for a BOPF at or below 0.04 lb/ton of steel for existing sources and 0.0017 lb/ton of steel for new sources; and g. Maintaining emissions of D/F TEQs from a primary emission control system for a BOPF at or below 9.2E–10 lb/ton of steel.
10. Each hot metal transfer, skimming, and desulfurization operation at a new or existing BOPF shop.	a. Maintaining emissions of particulate matter from a control device at or below 0.01 gr/dscf at an existing BOPF or 0.003 gr/dscf for a new BOPF; and b. Conducting subsequent performance tests at the frequencies specified in § 63.7821.
11. Each ladle metallurgy operation at a new or existing BOPF shop.	a. Maintaining emissions of particulate matter from a control device at or below 0.01 gr/dscf at an existing BOPF shop or 0.004 gr/dscf for a new BOPF shop; and b. Conducting subsequent performance tests at the frequencies specified in § 63.7821.
12. Each existing BOPF shop	a. Maintaining the opacity of secondary emissions that exit any opening in the BOPF shop or other building housing the BOPF shop or shop operation at or below 20 percent (3-minute average); and b. Conducting subsequent performance tests at the frequencies specified in § 63.7821.
13. Each new BOPF shop	a. Maintaining the opacity (for any set of 6-minute averages) of secondary emissions that exit any opening in the BOPF shop or other building housing a bottom-blown BOPF or shop operation at or below 10 percent, except that one 6-minute period greater than 10 percent but no more than 20 percent may occur once per steel production cycle; b. Maintaining the opacity (for any set of 3-minute averages) of secondary emissions that exit any opening in the BOPF shop or other building housing a top-blown BOPF or shop operation at or below 10 percent, except that one 3-minute period greater than 10 percent but less than 20 percent may occur once per steel production cycle; and c. Conducting subsequent performance tests at the frequencies specified in § 63.7821.
14. Each BOPF Group at an existing BOPF shop.	a. Maintaining emissions of mercury from the collection of BOPF Group control devices at or below 0.00026 lb/ton steel scrap input to the BOPF; and b. If demonstrating compliance through performance testing, conducting subsequent performance tests at the frequencies specified in § 63.7821; and c. If demonstrating compliance through § 63.7791(c), (d), or (e), maintaining records pursuant to § 63.7842(e).
15. Each BOPF Group at a new BOPF shop.	a. Maintaining emissions of mercury from the collection of BOPF Group control devices at or below 0.000081 lb/ton steel scrap input to the BOPF; and b. If demonstrating compliance through performance testing, conducting subsequent performance tests at the frequencies specified in § 63.7821; and c. If demonstrating compliance through § 63.7791(c), (d), or (e), maintaining records pursuant to § 63.7842(e).
16. Each planned bleeder valve opening at a new or existing blast furnace.	a. Maintaining the opacity of emissions that exit any bleeder valve as a result of a planned opening at or below 8 percent (6-minute average); and b. Conducting subsequent performance tests at the frequencies specified in § 63.7821.
17. Each slag processing, handling and storage operation for a new or existing blast furnace or BOPF.	a. Maintaining the opacity of emissions that exit any slag processing, handling, or storage operation at or below 10 percent (6-minute average); and b. Conducting subsequent performance tests at the frequencies specified in § 63.7821.
18. Each existing blast furnace stove	a. Maintaining emissions of HCl at or below 0.0012 lb/MMBtu; b. Maintaining emissions of THC at or below 0.12 lb/MMBtu; and c. Conducting subsequent performance tests at the frequencies specified in § 63.7821.
19. Each new blast furnace stove	a. Maintaining emissions of HCl at or below 4.2e–4 lb/MMBtu; b. Maintaining emissions of THC at or below 0.0054 lb/MMBtu; and c. Conducting subsequent performance tests at the frequencies specified in § 63.7821.

Table 4 to Subpart FFFFF of Part 63—Applicability of General Provisions to Subpart FFFFF

As required in § 63.7850, you must comply with the requirements of the NESHAP General Provisions (subpart A of this part) shown in the following table:

Citation	Subject	Applies to subpart FFFFF	Explanation
§ 63.1	Applicability	Yes.	
§ 63.2	Definitions	Yes.	
§ 63.3	Units and Abbreviations	Yes.	

Citation	Subject	Applies to subpart FFFFF	Explanation
§ 63.4	Prohibited Activities	Yes.	
§ 63.5	Construction/Reconstruction	Yes.	
§ 63.6(a), (b), (c), (d), (e)(1)(iii), (f)(2)–(3), (g), (h)(2)(ii)–(h)(9).	Compliance with Standards and Maintenance Requirements.	Yes.	
§ 63.6(e)(1)(i)	General Duty to Minimize Emissions	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes on or before January 11, 2021, and No thereafter.	See § 63.7810(d) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to Correct Malfunctions ASAP.	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes, on or before January 11, 2021, and No thereafter.	
§ 63.6(e)(3)	SSM Plan Requirements	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes on or before January 11, 2021, and No thereafter.	See § 63.7810(c).
§ 63.6(f)(1)	Compliance except during SSM	No	See § 63.7810(a).
§ 63.6(h)(1)	Compliance except during SSM	No	See § 63.7810(a).
§ 63.6(h)(2)(i)	Determining Compliance with Opacity and VE Standards.	No	Subpart FFFFF specifies methods and procedures for determining compliance with opacity emission and operating limits.
§ 63.6(i)	Extension of Compliance with Emission Standards.	Yes.	
§ 63.6(j)	Exemption from Compliance with Emission Standards.	Yes.	
§ 63.7(a)(1)–(2)	Applicability and Performance Test Dates.	No	Subpart FFFFF and specifies performance test applicability and dates.
§ 63.7(a)(3), (b)–(d), (e)(2)–(4), (f)–(h)	Performance Testing Requirements	Yes.	
§ 63.7(e)(1)	Performance Testing	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes on or before January 11, 2021, and No thereafter.	See §§ 63.7822(a), 63.7823(a), and 63.7825(a).
§ 63.8(a)(1)–(3), (b), (c)(1)(ii), (c)(2)–(3), (c)(4)(i)–(ii), (c)(5)–(6), (c)(7)–(8), (d)(1)–(2), (e), (f)(1)–(5), (g)(1)–(4).	Monitoring Requirements	Yes	CMS requirements in § 63.8(c)(4)(i)–(ii), (c)(5)–(6), (d)(1)–(2), and (e) apply only to COMS.
§ 63.8(a)(4)	Additional Monitoring Requirements for Control Devices in § 63.11.	No	Subpart FFFFF does not require flares.
§ 63.8(c)(1)(i)	General Duty to Minimize Emissions and CMS Operation.	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes on or before January 11, 2021, and No thereafter.	
§ 63.8(c)(1)(iii)	Requirement to Develop SSM Plan for CMS.	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes on or before January 11, 2021, and No thereafter.	
§ 63.8(c)(4)	Continuous Monitoring System Requirements.	No	Subpart FFFFF specifies requirements for operation of CMS.
§ 63.8(d)(3)	Written procedures for CMS	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes on or before January 11, 2021, and No thereafter.	See § 63.7842(b)(3).
§ 63.8(f)(6)	RATA Alternative	No.	
§ 63.8(g)(5)	Data Reduction	No	Subpart FFFFF specifies data reduction requirements.
§ 63.9	Notification Requirements	Yes	Additional notifications for CMS in § 63.9(g) apply only to COMS.
§ 63.10(a), (b)(1), (b)(2)(x), (b)(2)(xiv), (b)(3), (c)(1)–(6), (c)(9)–(14), (d)(1)–(4), (e)(1)–(2), (e)(4), (f).	Recordkeeping and Reporting Requirements.	Yes	Additional records for CMS in § 63.10(c)(1)–(6), (9)–(14), and reports in § 63.10(d)(1)–(2) apply only to COMS.
§ 63.10(b)(2)(i)	Recordkeeping of Occurrence and Duration of Startups and Shutdowns.	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes on or before January 11, 2021, and No thereafter.	

Citation	Subject	Applies to subpart FFFFF	Explanation
§ 63.10(b)(2)(ii)	Recordkeeping of Failures to Meet a Standard.	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes on or before January 11, 2021, and No thereafter.	See § 63.7842(a)(2)–(4) for recordkeeping of (1) date, time, and duration of failure to meet the standard; (2) listing of affected source or equipment, and an estimate of the quantity of each regulated pollutant emitted over the standard; and (3) actions to minimize emissions and correct the failure.
§ 63.10(b)(2)(iii)	Maintenance Records	Yes.	
§ 63.10(b)(2)(iv)	Actions Taken to Minimize Emissions During SSM.	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes on or before January 11, 2021, and No thereafter.	See § 63.7842(a)(4) for records of actions taken to minimize emissions.
§ 63.10(b)(2)(v)	Actions Taken to Minimize Emissions During SSM.	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes on or before January 11, 2021, and No thereafter.	See § 63.7842(a)(4) for records of actions taken to minimize emissions.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS Malfunctions	Yes.	
§ 63.10(b)(2)(vii)–(ix)	Other CMS Requirements	Yes.	
§ 63.10(b)(2)(xiii)	CMS Records for RATA Alternative	No.	
§ 63.10(c)(7)–(8)	Records of Excess Emissions and Parameter Monitoring Exceedances for CMS.	No	Subpart FFFFF specifies record requirements; see § 63.7842.
§ 63.10(c)(15)	Use of SSM Plan	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes on or before January 11, 2021, and No thereafter.	
§ 63.10(d)(5)(i)	Periodic SSM Reports	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes on or before January 11, 2021, and No thereafter.	See § 63.7841(b)(4) for malfunction reporting requirements.
§ 63.10(d)(5)(ii)	Immediate SSM Reports	No, for new or reconstructed sources which commenced construction or reconstruction after August 16, 2019. For all other affected sources, Yes on or before January 11, 2021, and No thereafter.	
§ 63.10(e)(3)	Excess Emission Reports	No	Subpart FFFFF specifies reporting requirements; see § 63.7841.
§ 63.11	Control Device Requirements	No	Subpart FFFFF does not require flares.
§ 63.12	State Authority and Delegations	Yes.	
§ 63.13–§ 63.16	Addresses, Incorporations by Reference, Availability of Information and Confidentiality, Performance Track Provisions.	Yes.	

■ 20. Add tables 5 and 6 to subpart FFFFF to read as follows:

Table 5 to Subpart FFFFF of Part 63—Toxic Equivalency Factors

As stated in § 63.7825(u), you must demonstrate compliance with each dioxin/furan emission limit that applies to you by calculating the sum of the 2,3,7,8-TCDD TEQs using the 2005 World Health Organization (WHO) toxicity equivalence factors (TEF) presented in the following table:

For each dioxin/furan congener . . .	You must calculate its 2,3,7,8-TCDD TEQ using the following TEF . . .
2,3,7,8-tetrachlorodibenzo-p-dioxin	1
1,2,3,7,8-pentachlorodibenzo-p-dioxin	1
1,2,3,4,7,8-hexachlorodibenzo-p-dioxin	0.1
1,2,3,7,8,9-hexachlorodibenzo-p-dioxin	0.1
1,2,3,6,7,8-hexachlorodibenzo-p-dioxin	0.1
1,2,3,4,6,7,8-heptachlorodibenzo-p-dioxin	0.01
Octachlorodibenzo-p-dioxin	0.0003
2,3,7,8-tetrachlorodibenzofuran	0.1
1,2,3,7,8-pentachlorodibenzofuran	0.03
2,3,4,7,8-pentachlorodibenzofuran	0.3
1,2,3,4,7,8-hexachlorodibenzofuran	0.1
1,2,3,6,7,8-hexachlorodibenzofuran	0.1

For each dioxin/furan congener . . .	You must calculate its 2,3,7,8-TCDD TEQ using the following TEF . . .
1,2,3,7,8,9-hexachlorodibenzofuran	0.1
2,3,4,6,7,8-hexachlorodibenzofuran	0.1
1,2,3,4,6,7,8-heptachlorodibenzofuran	0.01
1,2,3,4,7,8,9-heptachlorodibenzofuran	0.01
Octachlorodibenzofuran	0.0003

Table 6 to Subpart FFFFF of Part 63—List of Polycyclic Aromatic Hydrocarbons

As stated in § 63.7825(x), you must demonstrate compliance with each polycyclic aromatic hydrocarbon emission limit that applies to you by calculating the sum of the emissions of each polycyclic aromatic hydrocarbon in the following table:

Pollutant name	CAS No.
Acenaphthene	83–32–9
Acenaphthylene	208–96–8
Anthracene	120–12–7
Benz[a]anthracene	56–55–3
Benzo[a]pyrene	50–32–8
Benzo[b]fluoranthene	205–99–2
Benzo[g,h,i]perylene	191–24–2
Benzo[k]fluoranthene	207–08–9
Chrysene	218–01–9
Dibenz[a,h]anthracene	53–70–3
Fluoranthene	206–44–0
Fluorene	86–73–7
Indeno (1,2,3-cd) pyrene	193–39–5
Naphthalene	91–20–3
Phenanthrene	85–01–8
Perylene	198–55–0
Pyrene	129–00–0

[FR Doc. 2024–05850 Filed 4–2–24; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2017–0664; FRL–5925.1–01–OAR]

RIN 2060–AV58

National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is finalizing amendments to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Taconite Iron Ore Processing. Specifically, the EPA is finalizing maximum achievable control technology (MACT) standards for mercury (Hg) and establishing revised emission standards for hydrogen chloride (HCl) and hydrogen fluoride (HF). This final action ensures that emissions of all hazardous air pollutants (HAP) emitted from the Taconite Iron Ore Processing source category are regulated.

DATES: This final rule is effective March 6, 2024. The incorporation by reference (IBR) of certain publications listed in the rule is approved by the Director of the Federal Register (FR) as of March 6, 2024. The incorporation by reference of certain other material listed in the rule was approved by the Director of the Federal Register as of October 26, 2020.

ADDRESSES: The EPA established a docket for this action under Docket ID No. EPA–HQ–OAR–2017–0664. All documents in the docket are listed on the *https://www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and is publicly available only in hard copy. With the exception of such material, publicly available docket materials are available electronically in *https://www.regulations.gov/*or in hard copy at the EPA Docket Center, Room 3334, WJC West Building, 1301 Constitution Avenue NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact David Putney, Sector Policies and Programs Division (D243–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina, 27711; telephone number: (919) 541–2016; email address: *putney.david@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACI	activated carbon injection
BTF	beyond-the-floor
CAA	Clean Air Act
CBI	Confidential Business Information
CEMS	continuous emission monitoring system
CFR	Code of Federal Regulations
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DSI	dry sorbent injection
EJ	environmental justice
EPA	Environmental Protection Agency
ESP	electrostatic precipitator
FR	Federal Register
HAP	hazardous air pollutant(s)
HCl	hydrochloric acid
HF	hydrogen fluoride
Hg	mercury
ICR	information collection request
km	kilometer
LEAN	Louisiana Environmental Action Network
lb/LT	pounds of HAP (*i.e.,* Hg, HCl, or HF) emitted per long ton of pellets produced
MACT	maximum achievable control technology
MWh/yr	megawatt-hours per year
MPCA	Minnesota Pollution Control Agency
NAICS	North American Industry Classification System
NESHAP	National Emission Standards for Hazardous Air Pollutants
ng/g	nanograms per gram
NTTAA	National Technology Transfer and Advancement Act
OAQPS	Office of Air Quality Planning and Standards
OMB	Office of Management and Budget
PM	particulate matter
PRA	Paperwork Reduction Act
RFA	Regulatory Flexibility Act
RTR	residual risk and technology review
tpy	tons per year
UPL	upper prediction limit
μg/Nm3	microgram per normal cubic meter
UMRA	Unfunded Mandates Reform Act
VCS	voluntary consensus standards

Organization of this document. The information in this preamble is organized as follows:

I. General Information

A. Does this action apply to me?

Table 1 of this preamble lists the NESHAP and associated regulated industrial source category that is the subject of this final rule. Table 1 is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that this final action is likely to affect. The final standards are directly applicable to the affected sources. Federal, state, local, and Tribal government entities are not affected by this final action. As defined in the *Initial List of Categories of Sources Under Section 112(c)(1) of the Clean Air Act Amendments of 1990* (see 57 FR 31576; July 16, 1992) and *Documentation for Developing the Initial Source Category List, Final Report* (see EPA–450/3–91–030; July 1992), the Taconite Iron Ore Processing source category includes any facility engaged in separating and concentrating iron ore from taconite, a low-grade iron ore to produce taconite pellets. The source category includes, but is not limited to, the following processes: liberation of the iron ore by wet or dry crushing and grinding in gyratory crushers, cone crushers, rod mills, and ball mills; pelletizing by wet tumbling with a balling drum or balling disc; induration using a straight grate or grate kiln indurating furnace; and finished pellet handling.

TABLE 1—NESHAP AND SOURCE CATEGORIES AFFECTED BY THIS FINAL ACTION

Source category	NESHAP	NAICS code [1]
Taconite Iron Ore Processing	40 CFR part 63, subpart RRRRR	21221

[1] North American Industry Classification System.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action is available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this final action at *https://www.epa.gov/stationary-sources-air-pollution/taconite-iron-ore-processing-national-emission-standards-hazardous.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rule and key technical documents at this same website.

C. Judicial Review and Administrative Reconsideration

Under Clean Air Act (CAA) section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) by May 6, 2024. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. This section also provides a mechanism for the EPA to reconsider the rule if the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within the period for public comment or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule. Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, WJC South Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Background

A. What is the statutory authority for this action?

In the *Louisiana Environmental Action Network* v. *EPA* (''*LEAN*'') decision issued on April 21, 2020, the D.C. Circuit held that the EPA has an obligation to address regulatory gaps, such as missing standards for HAP known to be emitted from a major source category, when the Agency conducts the 8-year technology review required by CAA section 112(d)(6).[1] Emissions data collected from the exhaust stacks of existing taconite indurating furnaces indicate that Hg is emitted from the source category. However, Hg emissions from the Taconite Iron Ore Processing source category are not regulated under the existing Taconite Iron Ore Processing NESHAP. To meet the EPA's obligations under CAA section 112(d)(6), in this action, the EPA is establishing new standards for Hg emissions from the Taconite Iron Ore Processing source category that reflect MACT for Hg emitted from taconite indurating furnaces, pursuant to CAA sections 112(d)(2) and (3).

The EPA is also finalizing revised standards for HCl and HF pursuant to CAA section 112(d)(6). CAA section 112(d)(6) requires the EPA to review standards promulgated under CAA section 112 and revise them ''as necessary (taking into account developments in practices, processes, and control technologies)'' no less often than every 8 years.

B. What is the source category and how does the current NESHAP regulate its HAP emissions?

The Taconite Iron Ore Processing NESHAP (codified at 40 Code of Federal Regulations (CFR) part 63, subpart RRRRR) applies to each new or existing ore crushing and handling operation, ore dryer, pellet indurating furnace, and finished pellet handling operation at a taconite iron ore processing plant that is (or is part of) a major source of HAP emissions. Taconite iron ore processing plants separate and concentrate iron ore from taconite, a low-grade iron ore containing 20- to 25-percent iron, and produce taconite pellets, which are 60- to 65-percent iron. The current NESHAP includes particulate matter (PM) limits that, prior to this final action, served as a surrogate for particulate metal HAP, HCl, and HF emissions. The existing PM emissions limits were summarized in table 2 of the proposal (see 88 FR 30917; May 15, 2023). The current NESHAP does not presently include standards for Hg emissions.

There are currently eight taconite iron ore processing plants in the United States: six plants are located in Minnesota and two are located in Michigan. This includes the Empire Mining facility in Michigan, which maintains an air quality permit to operate, but has been indefinitely idled since 2016 and is therefore not included

---

[1] *Louisiana Environmental Action Network* v. *EPA,* 955 F.3d 1088 (D.C. Cir. 2020) (''*LEAN*'').

in any analyses (*e.g.,* estimates of emissions or cost impacts) associated with this final rulemaking.

C. What changes did we propose for the Taconite Iron Ore Processing source category?

On May 15, 2023, the EPA published a proposal in the **Federal Register** to set MACT standards for Hg emissions from indurating furnaces in the source category and to revise the existing emission standards for HCl and HF for indurating furnaces. The PM emission limits in the current NESHAP will continue to serve as surrogate for particulate metal HAP (*e.g.,* nickel and arsenic). The EPA proposed that compliance with the emission standards for Hg, HCl, and HF be demonstrated through operating limits, monitoring, and performance testing. We also proposed minor changes to the electronic reporting requirements found in 40 CFR 63.9641(c) and 40 CFR 63.9641(f)(3) to reflect new procedures for reporting CBI that included an email address for owners and operators to electronically submit compliance reports containing CBI to the Office of Air Quality Planning and Standards (OAQPS) CBI Office. Finally, we requested comment on our evaluation that the addition of 1-bromopropane (1–BP) to the CAA section 112 HAP list would not impact the Taconite Iron Ore Processing NESHAP because, based on our knowledge of the source category and available emissions data, 1–BP is not emitted from this source category.

III. What is the rationale for our final decisions and amendments for the Taconite Iron Ore Processing source category?

For each issue, this section provides a description of what we proposed and what we are finalizing, a summary of key comments and responses, and the EPA's rationale for the final decisions and amendments. For all comments not discussed in this preamble, comment summaries and the EPA's responses can be found in the document, *Summary of Public Comments and Responses for Proposed Amendments to the National Emission Standards for Hazardous Air Pollutants for Taconite Iron Ore Processing,* which is available in the docket for this action.

A. MACT Standards for Mercury

1. What did we propose for the Taconite Iron Ore Processing source category?

As described in the May 15, 2023, proposal (88 FR 30917), we proposed MACT standards for Hg for new and existing indurating furnaces that reflected the MACT floor level of control, based on the 99-percent upper prediction limit (UPL), of 1.4×10^{-5} pounds of Hg emitted per long ton of taconite pellets produced (lb/LT) for existing sources and 3.1×10^{-6} lb/LT for new sources. We also proposed an emissions averaging compliance alternative that would allow taconite iron ore processing facilities with more than one existing indurating furnace to comply with a Hg emissions limit of 1.26×10^{-5} lb/LT by averaging emissions on a production-weighted basis for two or more existing indurating furnaces located at the same facility. In the proposal, we explained that the emissions averaging compliance alternative reflected a 10 percent adjustment factor to the proposed MACT floor standard and that we expected this 10 percent adjustment factor would result in Hg reductions greater than those achieved by compliance with the MACT floor on a unit-by-unit basis. We proposed that compliance with the Hg MACT standards would be demonstrated through initial and periodic performance testing (completed at least twice per 5-year permit term), establishing operating limits for each control device used to comply with the Hg standards, and installing and operating continuous parameter monitoring systems (CPMS) to ensure continuous compliance with the Hg standards.

For the proposal, in addition to calculating the MACT floor, pursuant to CAA section 112(d)(2), we also assessed more stringent ''beyond-the-floor'' (BTF) regulatory options for the Hg MACT standards. As discussed in the proposal (88 FR 30923), unlike the MACT floor's minimum stringency requirements, the EPA must examine various impacts of the more stringent BTF regulatory options in determining whether MACT standards are to reflect BTF requirements. These impacts include the cost of achieving additional emissions reductions beyond those achieved by the MACT floor level of control, any non-air quality health and environmental impacts that would result from imposing controls BTF, and energy requirements of such BTF measures. If the EPA concludes that the more stringent regulatory options have unreasonable impacts, the EPA selects the MACT floor level of control as MACT. However, if the EPA concludes that impacts associated with BTF levels of control are reasonable in light of additional HAP emissions reductions achieved, then the EPA selects those BTF levels as MACT.

We considered BTF regulatory options that were 10, 20, 30, and 40 percent more stringent than the MACT floor and calculated the capital and annual costs as well as secondary impacts associated with each option. For a detailed discussion of our analysis of emissions reductions and potential secondary impacts developed for the proposal, please see the memorandum, *Development of Impacts for the Proposed Amendments to the NESHAP for Taconite Iron Ore Processing,* which is available in the docket for this action. We proposed that requiring new or existing furnaces to meet BTF emission limits was not reasonable based on the estimated capital and operating costs and cost-effectiveness.

2. What comments did we receive on the proposed Hg MACT standards, and what are our responses?

Comment: Industry commenters provided data that they indicated corrected the Hg stack test data submitted in response to the CAA section 114 Information Collection Request (ICR) sent to the taconite facilities in 2022 for the Tilden, UTAC, Keetac, and Hibbing facilities that were used when calculating the baseline emissions, the MACT floor standards, and the emission reductions. The commenters indicated that the error in the Keetac emissions data resulted in an overestimate of both the baseline emissions and the estimated emission reductions that could be achieved if the proposed Hg standards were adopted.

Response: In response to these comments and revised data provided, the EPA reviewed the Hg emissions data that we used in the proposal to calculate baseline Hg emissions. At proposal we estimated total baseline Hg emissions were 1,010 pounds per year. The EPA confirmed that errors were present in the Hg emissions data used to calculate the baseline emissions. We revised the emissions data as appropriate based on the emissions data provided by industry commenters and recalculated the baseline emissions, MACT floor emission limits, emission reductions, and estimated capital and annual costs accordingly for the final rule. The updates to the emissions data did not impact the MACT floor limit for existing sources but did decrease the baseline emissions and the expected Hg emissions reductions for existing sources. The updates to the emissions data changed the Hg standard for new sources from 3.1×10^{-6} lb/LT to 2.6×10^{-6} lb/LT. The updated baseline Hg emissions for the final rule are estimated to be 751 pounds per year (0.38 tons per year (tpy)). We estimate that unit-by-unit compliance with the final MACT floor limit will result in a reduction of 232 pounds of Hg emissions per year and a reduction of 247 pounds per year of Hg emissions if all facilities with more than one existing taconite furnace elect to demonstrate compliance through the emissions averaging compliance alternative. Our analysis is presented in detail in the memorandum, *Development of Impacts for the Final Amendments to the NESHAP for Taconite Iron Ore Processing.* The updated emissions data used in the revised calculations for the final rule are summarized in a separate memorandum, *Final Emissions Data Collected in 2022 for Indurating Furnaces Located at Taconite Iron Ore Processing Plants.* These documents are available in the docket for this action.

Comment: One commenter recommended the proposed limit for the emissions averaging compliance alternative for existing sources should have the same number of significant figures as the MACT floor limit. Instead of 1.26×10^{-5} lb/LT, the limit for the emissions averaging compliance alternative for existing sources would be rounded up to 1.3×10^{-5} lb/LT.

Response: The EPA agrees with the commenter that the Hg emission limit for the emissions averaging compliance option should have only two significant figures. The limit cannot have more significant figures than Hg MACT floor from which it was derived, which has only two significant figures. As recommended by commenters, the Hg emission limit in the final rule is revised to 1.3×10^{-5} lb/LT so that the limit for the emissions averaging compliance alternative has the same number of significant figures as the other Hg limits finalized in this rulemaking.

We estimate that the final Hg emissions averaging compliance alternative will reduce Hg emissions by 247 pounds per year, if Hibbing and Minntac elect to demonstrate compliance through the emissions averaging compliance alternative by each facility installing mercury controls on two furnaces and averaging the emissions across all furnaces located at their facility. We expect that, should Hibbing and Minntac elect to demonstrate compliance through the emissions averaging compliance alternative, the Hg reductions would still be greater than the reductions we anticipate would be achieved through unit-by-unit compliance with the MACT floor level of control. For additional details, please refer to section IV.A.1 of the proposal preamble (88 FR 30925). More information on the final Hg standards, including the detailed cost estimates for the Hg emissions averaging compliance alternative, may be found in the memorandum, *Development of Impacts for the Final Amendments to the NESHAP for Taconite Iron Ore Processing,* which is available in the docket for this action.

Comment: Commenters recommended that the proposed 40 CFR 63.9621(d)(4) and 63.9631(j) be revised to allow the mass of taconite pellets produced to be determined indirectly through calculation based on industry standards. They noted that pellet mass is measured prior to offsite shipment and later "trued-up" at the end of each month.

Response: The EPA agrees that taconite pellet production can be determined indirectly through calculation using bulk density and volume measurements. We have revised the language in 40 CFR 63.9621(d)(4) and 63.9631(j) to allow the weight of taconite pellets produced to be determined either by direct measurement using weigh hoppers, belt weigh feeders, or weighed quantities in shipments, or calculated using the bulk density and volume measurements.

Comment: Industry commenters stated that the capital and operating costs for Hg controls were underestimated in the proposal and that the estimated capital costs were significantly below cost estimates developed by industry. The commenters thought the retrofit factor of 1.2 used by the EPA failed to adequately account for the additional costs incurred when retrofitting an existing emission unit with new controls. They recommended the EPA use the capital costs prepared by industry and apply a retrofit factor of 1.5 or 1.6 with a contingency factor of 30 percent to account for the higher costs for retrofit projects. The commenters also stated that the total annual costs were underestimated because the EPA had underestimated costs for activated carbon, electricity, and waste disposal and used an interest rate that was too low. Industry commenters also stated that currently, some plants recycle iron particles collected by their particulate emission control device, but that the presence of activated carbon would create product quality issues and make recycling no longer possible. The commenters stated the EPA had not accounted for the loss of product and increased waste disposal costs in the cost estimates prepared for the proposal. The commenters provided cost estimates for the Keetac, Minorca, Minntac and UTAC facilities that included estimates of the amount of product they assert would be lost if scrubber solids are not recycled back through the process and the estimated price for the lost product. The commenters also disagreed with the estimated labor costs, arguing that both the number of operator hours and hourly labor rates were too low.

Response: For the final rule, the EPA has updated the capital and annual costs to reflect the costs in 2023 dollars using an interest rate of 8.5 percent and updated unit prices for activated carbon, utilities, and labor. The EPA also assessed the commenters concerns that ACI would prevent plants from recovering iron particles collected with other solids by their particulate emission control device. Based on the information provided by industry, ten indurating furnaces currently collect the solids from their particulate control devices and recycle the solids back to the production process, thereby recovering valuable iron product. Commenters said plants using ACI would not be able to continue to recover iron in this way because carbon would impact the quality of their product. Commenters said EPA should account for costs due to the loss of product and increased cost of waste disposal of the unrecoverable product. Industry provided estimates of the amount of iron that would be lost for the furnaces located at the UTAC, Minorca, and Minntac plants. We used this data to estimate iron losses for the Hibbing plant and multiplied the estimated iron losses for each furnace by the current market price of iron to estimate the costs associated with the loss iron product. The updated cost estimates that we are using for the final rule, including the basis for the 8.5 percent interest rate, are documented in the memorandum, *Development of Impacts for the Final Amendments to the NESHAP for Taconite Iron Ore Processing,* which is available in the docket for this action.

The EPA reviewed the capital cost information submitted by industry during the comment period and found the information submitted consisted of a total capital cost for equipment. However, no breakdown was provided from which we could ascertain what was included in the cost and little information was provided on how the costs were derived. The lack of detail in the cost estimates combined with little supporting documentation made it impossible for the EPA to assess the accuracy of the cost estimates submitted by industry. Industry commenters indicated that the estimated equipment costs for the air pollution control equipment for the Minorca and UTAC facilities they submitted were estimated using cost data from another project at a different facility and scaled using the 'rule of six-tenths.' The 'rule of six-tenths' is a method by which equipment costs are estimated as the cost of a known project multiplied by a capacity factor raised to the power of six-tenths. The 'rule of six-tenths' can provide a reasonable order of magnitude estimate of equipment costs where the capacities of the two systems are reasonably similar. However, the commenters did not identify the facility or provide a detailed description of the project to which they are applying the rule of six-tenths. Commenters also failed to provide a detailed breakdown of the equipment costs used in the 'rule of six-tenths' estimate. Without additional information, the EPA was unable to assess the accuracy of the equipment costs provided by commenters. Therefore, we are not making any changes based on this information.

We disagree with the commenters' recommendations that a retrofit factor of 1.5 or 1.6 should be applied to the capital costs with a 30-percent contingency factor. Retrofit factors account for costs directly related to the demolition, fabrication, and installation of the control system. For the venturi scrubbers we included the 3-percent contingency factor and applied a retrofit factor of 1.2 to the estimate of the total capital investment for new construction. The EPA's *Air Pollution Control Cost Manual* indicates a 3-percent contingency factor is considered appropriate for a mature air pollution control technology and states that retrofit costs are ''generally minimal'' for venturi scrubbers because of their small footprint.[2] While we agree with the commenters that retrofits may, in some cases, be more expensive than new construction, the 1.2 retrofit factor used in the cost estimates provides a reasonable increase to account for the higher cost associated with retrofit projects that involve replacing an existing venturi scrubber with a high-efficiency venturi scrubber, where infrastructure (*e.g.,* water and power supply) already exist. The retrofit factor applied does not have a significant impact on the total annual costs. If a retrofit factor of 1.6 is applied, as recommended by the commenters, the total annual costs would increase by about 2 percent (less than $2 million for replacing the venturi scrubbers on all 11 furnaces with mercury emissions currently exceeding the MACT floor. We did not apply a retrofit factor to the capital costs for the activated carbon injection (ACI) system because the costs were estimated using a methodology developed by Sargent & Lundy for the EPA's Integrated Planning Model (IPM).[3] The IPM methodology is based on costs for retrofitting ACI on utility boilers and therefore already represents the average or typical costs for ACI retrofits.

A contingency factor is reserved for costs that could incur a reasonable but unanticipated increase but are not directly related to the demolition, fabrication, and installation of the system. Retrofit and contingency factors can be difficult to assess as they vary based on site-specific characteristics. Nevertheless, the EPA considers the methodology used to calculate capital and total annual costs to be a reasonable approach to estimating costs for the purposes of this rulemaking. We note that the EPA may not consider costs in determining the MACT floor, and that the cost estimates for the BTF control options identified for Hg emissions were determined to be greater than the level historically found to be cost-effective for controlling Hg emissions.

Comment: Industry commenters noted that the Hg concentrations in taconite ore deposits vary widely both within each mine and between mines, which in turn affects Hg emissions. The commenters said the primary source of Hg emissions from indurating furnaces is from the Hg contained in the greenballs (*i.e.,* unfired taconite iron ore pellets). The commenters provided Hg concentration data for greenballs from each taconite iron ore processing facility and recommended that the EPA revise the proposed Hg limits for new and existing furnaces to address the variability inherent in the Hg concentration of greenballs. They suggested the EPA use the data to develop a raw material variability factor that could be used when calculating the MACT floor limits for Hg. The commenters noted that the EPA had accounted for variability in the Hg concentration of raw materials when calculating the MACT floor limits for other NESHAP.

Response: The EPA reviewed the Hg data submitted by industry and determined the data were not adequate for us to calculate a variability factor for use in deriving the MACT floor limits. This decision was based on several factors. First, the number of measurements submitted for each facility varied considerably—from as few as three measurements for the best performing furnace at Northshore (including two measurements on the same day) to as many as 948 measurements for the UTAC plant. The very limited data provided for Northshore is a concern because Northshore's stack test data showed that their furnace was the best performing (*i.e.,* had the lowest emissions of Hg). The data provided for Northshore are insufficient to evaluate temporal variability in the Hg content of the greenballs at Northshore because the data consist of measurements made during only two greenball sampling episodes: one in January 1997 and the other in November 2001. Second, much of the data submitted could not be validated because the commenters did not provide the laboratory reports for the test results. For example, the UTAC facility provided 948 measurements of the Hg concentration of the greenballs at their plant but submitted none of the laboratory reports needed to corroborate their data. Laboratory reports are needed to determine whether appropriate methods were used for sample collection and analysis, to confirm appropriate quality assurance and quality control measures were taken, and to check that the values submitted are accurate. In total, we were unable to confirm the concentration values for over 87 percent of the measurements submitted because we lacked the laboratory reports. Third, the samples were collected at irregularly spaced intervals, often with large gaps in time during which no samples were collected. These sampling intervals varied from as little as a few days to multiple years. In cases where samples were collected over a period of several consecutive months, the measurements were not collected at consistent intervals. Ideally, the samples would be collected at representative intervals with supporting documentation of the sample collection and analysis, to avoid bias in the dataset. Finally, the data submitted for some facilities included measurements that we determined to be statistical outliers. For example, we identified two statistical outliers in the Tilden dataset, where in one case the Hg content of greenballs increased from 1.4 nanograms per gram (ng/g) on July 6, 2022, to 15.0 ng/g on July 15, 2022, before decreasing to 1.2 ng/g on July 22, 2022. The presence of statistical outliers does not necessarily mean the

---

[2] EPA's *Control Cost Manual* provides guidance for the development of capital and annual costs for air pollution control devices. The *Control Cost Manual* focuses on point source and stationary area source air pollution controls. A copy of the manual is available at *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.*

[3] Sargent & Lundy, LLC, *IPM Model—Updates to Cost and Performance for APC Technologies Mercury Control Cost Development Methodology,* January 2017. A copy of this document is available at *https://www.epa.gov/sites/default/files/2018-05/documents/attachment_5-6_hg_control_cost_development_methodology.pdf.*

measurements are incorrect. However, statistical outliers raise concerns over the accuracy and representativeness of the measurements, particularly where no explanation for the anomaly is available.

Comment: Some commenters requested EPA Method 30B be included as an acceptable alternative test method for measuring Hg emissions from indurating furnaces.

Response: In response to the commenters' request, we reviewed EPA Method 30B and determined that this method is appropriate for measuring Hg emissions from indurating furnaces. In the final rule, we have updated the list of approved methods for Hg measurement to include EPA Method 30B, in addition to the proposed methods. The final rule allows owners and operators to use EPA Methods 29 or 30B in 40 CFR part 60, appendix A–8, and the voluntary consensus standard (VCS), ASTM D6784–16, *Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method).*

Comment: Industry commenters expressed concern that the proposed Hg stack testing volumes for performance testing to demonstrate compliance with the proposed Hg standards were too large such that each test run would require too much time to complete. They recommended that smaller test volumes would be appropriate and suggested that the test volume be small enough to allow each test run to be completed within 60 minutes.

Response: In response to the commenters' concerns regarding the stack testing volumes and duration of each test run, the EPA reconsidered the proposed sample volume requirements and revised the performance testing requirements in the final rule to require a minimum sample volume of 1.7 dry standard cubic meters (dscm) (60 dry standard cubic feet (dscf)) for EPA Method 29 and ASTM D6784–16, instead of the 3 dscm sample volume we proposed. The 1.7 dscm sample volume will allow test runs to be completed in approximately 2 hours while still ensuring that the required sample volume is sufficient for analysis and that a non-detect test result indicates compliance with the final Hg limits.

Comment: We received multiple comments recommending continuous emission monitoring systems (CEMS) for Hg be included either as a requirement for all indurating furnaces or as an optional alternative to conducting performance testing and establishing operating limits. The commenters stated that CEMS would ensure continuous compliance with the Hg standard and could help lower compliance costs by making it possible for facilities to vary the ACI rate based on the Hg emissions data collected by CEMS. Some commenters said facilities would be more likely to use CEMS if the CEMS provisions were incorporated into the rule because facilities would not have to apply for approval of an alternative monitoring method.

Response: The EPA agrees with recommendations made by commenters that suggested CEMS be included as an optional alternative to the proposed compliance monitoring and performance testing requirements. We agree that CEMS are an acceptable alternative monitoring method for assuring compliance with the Hg emissions standards. In the final rule, we have included provisions that provide owners and operators the option of using Hg CEMS in lieu of establishing operating limits and performing periodic performance testing. These provisions will provide more options for the methods that facilities can use to demonstrate compliance with the new Hg standards and reduce the burden associated with applying for Administrator approval of an alternative monitoring plan. However, we are not requiring installation of CEMS due to compliance cost considerations, as explained in the memorandum, *Development of Impacts for the Final Amendments to the NESHAP for Taconite Iron Ore Processing,* which is available in the docket for this action.

Comment: Industry commenters were concerned that the proposed approach to setting operating limits for ACI would not allow facilities flexibility to adjust the carbon injection rates when production decreases. These commenters suggested the EPA allow flexibility to adjust the average ACI rate and average carrier flow rate based on taconite pellet production rates during stack testing to provide facilities with the operational flexibility needed at lower production rates.

Response: We agree with the industry commenters that lower ACI and carrier gas flow rates would achieve compliance with the emission limit when production rates are lower than the production rates during the performance test used to establish operating limits. We have included provisions in the final rule that allow a facility to adjust the operating limits based on taconite pellet production. Under the requirements of the final rule, a facility has the option of establishing operating limits for different production rates by conducting performance tests at the maximum, minimum, and median taconite pellet production rates of an indurating furnace to develop a relationship between the carbon injection rate and taconite pellet production rate. An owner or operator would monitor the taconite pellet production rate and adjust the ACI rate in accordance with the relationship between these parameters developed during the performance testing. If the taconite pellet production rate falls below the minimum rate measured during performance testing, the owners and operators must maintain a carbon injection rate that is equal to, or above, the rate determined during the performance testing completed at the minimum taconite production rate.

As an alternative, an owner or operator may adjust the ACI rate based on the direct measurement of Hg emitted to the atmosphere. An owner or operator must install, calibrate, maintain, and operate CEMS to measure Hg emissions from each emission stack associated with the indurating furnace to use this alternative.

Comment: Industry commenters supported the EPA's decision to set the Hg emissions standards at the MACT floor rather than setting a BTF standard. Industry commenters stated that the capital and annual costs required to comply with the MACT floor are too high and setting BTF standards would not be cost-effective. One commenter asserted that any standard beyond the MACT floor must be justified by a ''thorough and robust analysis of the costs and benefits.'' The commenter agreed with the EPA's proposed determination that the cost-effectiveness of the BTF options identified for Hg control were above the level historically found to be reasonable.

Several other commenters recommended the EPA set a BTF Hg standard and recommended the standard be at least 30–40 percent more stringent than the MACT floor. The commenters stated that additional Hg reductions can be achieved and that a more stringent Hg standard is warranted due to the bioaccumulative nature of Hg. The commenter noted that many water bodies located near taconite facilities already have fish consumption advisories, which commenters noted impact the rights of tribes to exercise their traditional life practices. One commenter noted that tribes have a particular interest in Hg emissions due to the Hg-related fish consumption advisories that have been issued by Minnesota since the 1970s and by the Fond du Lac Tribe beginning in 2000. One commenter stated that the 30 percent BTF option would reduce Hg emissions to a level that would help address public health concerns associated with high concentrations of Hg in water, fish tissues, and other subsistence resources. Commenters from several tribes located near taconite facilities stated that the EPA's Tribal trust and treaty responsibilities justified adoption of a BTF option. They added that the EPA should consider its trust responsibility to protect the interests of tribes and the tribes' treaty rights and quoted from two EPA policy documents: *EPA Policy for the Administration of Environmental Programs on Indian Reservations* (issued November 1984) and *Guidance for Discussing Tribal Treaty Rights* (issued February 2016). Both documents support consideration of Tribal rights and protections in Agency decision making. Commenters noted that the areas impacted by taconite iron ore processing plants are in the areas covered by a series of treaties. These commenters disagreed with the EPA's determination that BTF options were not cost-effective.

Response: The EPA agrees with the commenters that said the Hg standard should be set at the MACT floor. In our analysis, the BTF options were above the numbers we have found cost effective for Hg controls in prior CAA section 112 rulemakings.

The EPA recognizes the Federal government's trust responsibility, which derives from the historical relationship between the Federal government and Indian Tribes. The EPA acts consistently with the Federal government trust responsibility by implementing the statutes it administers and consulting with and considering the interests of tribes when taking actions that may affect them. As we noted in the proposal, the EPA consulted with Tribal government officials during the development of this rule. The EPA's Office of Air and Radiation held a meeting with the Fond du Lac Band of Lake Superior Chippewa Reservation and the Leech Lake Band of Ojibwe Reservation on January 12, 2022, to discuss the EPA's CAA section 114 information request, and to ensure that the views of affected tribes were taken into consideration in the rulemaking process in accordance with the *EPA Policy on Consultation and Coordination with Indian Tribes.* A summary of that consultation is provided in the document, *Consultation with the Fond du Lac Band of Lake Superior Chippewa and the Leech Lake Band of Ojibwe regarding Notice of Proposed Rulemaking for the National Emission Standards for Hazardous Air Pollutants for Taconite Iron Ore Processing Amendments on January 12, 2022,* which is available in the docket for this action.

The Agency recognizes the concerns raised by numerous Tribal commenters regarding impacts to treaty fishing and other resource rights. However, for the reasons explained below, the EPA is declining to set BTF standards for Hg, based on the statutory factors that we are required to consider pursuant to CAA section 112(d)(2) when assessing whether to set MACT standards more stringent than the MACT floor level of control. These statutory factors include the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements. As discussed in paragraphs later in this section, the cost-effectiveness values associated with BTF standards for this Taconite Iron Ore Processing rule are well above the cost-effectiveness values that EPA has historically accepted when considering BTF options for regulating mercury emissions. We note that the historic acceptable cost-effectiveness values for mercury (*e.g.,* up to $22,400 per pound [in 2007 dollars] in the 2011 final MATS rule, which equates to about $32,000 per pound in current dollars) are much higher than the cost-effectiveness values we have accepted for all other HAPs (except for maybe a few exceptions such as dioxins and furans) and is based, at least in part, on the fact that mercury is a persistent, bioaccumulative, toxic (PBT) HAP. Nevertheless, we conclude that setting BTF Hg standards in this rule would be inconsistent with the values found to be cost-effective for Hg controls in prior rulemakings. We are declining to set BTF standards in this rule based on cost and other statutory factors.

Section 112(d) of the CAA requires the EPA to set emissions standards for HAP emitted by sources in each source category and subcategory listed under CAA section 112(c). The MACT standards for existing sources must be at least as stringent as the average emissions limitation achieved by the best performing 12 percent of existing sources (for which the Administrator has emissions information) or the best performing five sources for source categories with less than 30 sources (CAA sections 112(d)(3)(A) and (B)). This level of minimum stringency is called the MACT floor. For new sources, MACT standards must be at least as stringent as the control level achieved in practice by the best controlled similar source (CAA section 112(d)(3)). The EPA may not consider costs or other impacts in determining the MACT floor.

Section 112(d)(2) of the CAA also requires the EPA to examine emission standards more stringent than the MACT floor, which the EPA refers to as BTF control options. Unlike standards set at the MACT floor level of control, when assessing whether to require emission standards more stringent than the MACT floor, the EPA must consider the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements. The EPA's BTF analysis evaluated these factors in determining whether to establish Hg standards more stringent than the MACT floor. In developing this final rule, we evaluated Hg emission limits more stringent than the MACT floor after adjusting estimates of Hg emissions, Hg emission reductions, and control costs as discussed above, including those BTF limits suggested by commenters, to assess whether a BTF option was technically achievable and cost-effective. We estimate that the total capital costs and total annual costs would range from a low of $137 million and $92 million, respectively, for a limit that is 10 percent more stringent than the floor to a high of $148 million and $102 million, respectively, for a limit that is 40 percent more stringent than the floor. The incremental cost effectiveness for the BTF options examined varied from a low of $46,266 per pound of Hg reduced for 30 percent more stringent than the floor to a high of $91,140 per pound of Hg reduced for 40 percent more stringent than the floor. These values are well above the $/pound of Hg reduced that we have historically found to be cost-effective when considering BTF options for regulating Hg emissions. Where EPA has taken costs into account, the Agency has finalized standards for mercury with cost effectiveness estimates of up to $32,000/lb Hg reduced (adjusted to 2024 dollars). See Mercury Cell Chlor-Alkali Plants Residual Risk and Technology Review (87 FR 27002, May 6, 2022); 2011 Mercury and Air Toxics (MATS) final rule. To date, these are the highest cost-effectiveness values that we have accepted in the air toxics program for any HAP (except for maybe a few exceptions such as dioxins and furans), largely because of the toxicity and nature of Hg. While we conclude that mercury standards more stringent than the MACT floor are not cost-effective, we note that as a result of the revisions to the rule being finalized in this rulemaking, we will receive compliance test information that will allow us to evaluate our conclusions and potentially inform appropriate future regulatory activities including the next statutorily required technology review. Mercury is one of the high concern HAPs because it is environmentally persistent, it bioaccumulates in humans and food chains—including in fish, which is a concern for subsistence needs, uses and cultural practices as noted in multiple comments from Tribes—and is a neurotoxin that is especially of concern for developing fetuses and young children. For these reasons, mercury is one of the few HAPs for which we use the expression of $ per pound and consider higher cost-effectiveness values. We also estimated the secondary impacts of the BTF options would range between 155,000 megawatt-hours per year (MWh/yr) and 160,000 MWh/yr of electricity (with associated secondary air emissions), generate between 4.7 million and 7.4 million gallons of wastewater per year, and produce between 110,000 tons and 112,000 tons of solid waste of per year. Based on our assessment of Hg emission standards 10 percent, 20 percent, 30 percent, and 40 percent more stringent than the MACT floor, including consideration of cost and other statutory factors of setting BTF Hg standards for indurating furnaces in the source category as specified in CAA section 112(d)(2), in the final rule, we are declining to adopt BTF emission standards for Hg and are finalizing Hg standards at the MACT floor as discussed in section III.A.3 of this preamble. For more information on our analysis of the BTF control options for Hg, please see the memorandum, *Final Maximum Achievable Control Technology (MACT) Analysis for Mercury Standards for Taconite Iron Ore Indurating Furnaces,* which is available in the docket for this action.

Comment: Several commenters, including the National Park Service, several local tribes, and environmental organizations said Hg standards for the taconite industry were important because of the benefits lower Hg emissions will have on public health and the environment. One commenter cited several studies, such as the Dragonfly Mercury Project, that document elevated levels of Hg and higher risks of Hg exposure to humans and wildlife in the Great Lakes Region. This commenter stated that the upper Great Lakes Region is particularly sensitive to Hg pollution due to the abundance of wetlands and peatlands, low-pH lakes, high dissolved organic matter, low biological productivity, and other factors that provide conditions suitable for the conversion of Hg to the bioavailable form methylmercury. The commenter also stated the impacts of Hg on wildlife include reduced foraging efficiency, lower reproductive success, impaired endocrine modulation, and damage to kidney and other tissues. The commenters expressed concern over the number of fish with Hg levels exceeding the human and wildlife health thresholds. The commenter cited data from a 1998–2016 study that measured Hg concentrations in fish from the upper Great Lakes at 0.12 ppm wet weight, with 24 percent of the fish sampled exceeding the EPA human health criterion of 0.3 ppm wet weight, 27 percent of the fish exceeding fish-eating wildlife health threshold of 0.2 ppm whole-body, and 17 percent exceeding the fish toxicity benchmark of 0.3 ppm whole-body. This commenter cited studies linking Hg deposition with bioaccumulation, including a study of Hg concentration in moose teeth from Isle Royale National Park, Michigan from 1952 to 2002. The commenter noted that Hg decreased by about two-thirds during the early 1980s but remained constant for the following 2 decades. The commenter cited an additional six studies that analyzed the concentrations and trends of Hg in bald eagle nestlings in the upper Midwest from 2006–2015 and long-term trends at two Lake Superior sites between 1989–2015. These studies show concentrations of Hg in nestling breast feathers were highest at the Saint Croix National Scenic Riverway (6.66 µg/g wet weight) and that Hg concentrations have increased at two other study area sites.

The commenters said the new Hg standards will help reduce Hg deposition in the Great Lakes Region and improve public health. The commenters asserted that taconite iron ore processing plants in Minnesota and Michigan have a significant impact on the natural resources of the upper Great Lakes Region and the elevated Hg levels in fish and bird populations. Several commenters mentioned the statewide fish consumption advisories for Hg in Minnesota, Michigan, and Wisconsin and noted several water bodies in these states are listed as impaired for aquatic consumption due to Hg. The commenters asserted that the new Hg standards will reduce the impact of Hg on public health and the environment, provide additional protection to recreational and subsistence fish consumers in national parks and surrounding communities, and protect natural resources that are of cultural significance to many local communities.

Response: The EPA acknowledges the independent research conducted by the National Park Service and others on the impacts of Hg on the communities and wildlife of the upper Great Lakes Region. We share the commenters' concern about the elevated Hg levels in fish and other wildlife in Minnesota, Wisconsin, and Michigan, and the critical impact these Hg levels have on tribes and low-income populations that rely on the fish and wildlife from the Great Lakes region. By controlling Hg emissions, the Hg MACT standards EPA is finalizing in this action for taconite iron ore processing plants will achieve an estimated reduction of 247 pounds per year of mercury emissions from the Taconite facilities, which we expect will also achieve an unquantified reduction of Hg deposition in the Great Lakes Region and therefore improve public health of local communities, including local tribes and low-income populations.

3. What are the final MACT standards for Hg and how will compliance be demonstrated?

We are finalizing MACT standards for Hg for new and existing indurating furnaces that reflect the MACT floor level of control, based on the 99-percent UPL, of 1.4×10^{-5} lb/LT for existing sources and 2.6×10^{-6} lb/LT for new sources. We are also finalizing the emissions averaging compliance alternative that allows taconite iron ore processing facilities with more than one existing indurating furnace to comply with a Hg emissions limit of 1.3×10^{-5} lb/LT by averaging emissions on a production-weighted basis for two or more existing indurating furnaces located at the same facility.

Owners and operators may demonstrate compliance with the new Hg standards in one of two ways. Under the first option, an owner or operator may demonstrate compliance by completing performance testing and establishing operating limits for each control device used to comply with the Hg standard. The final rule clarifies that performance testing must be performed when the production rate is equal to or greater than 90 percent of the capacity of the indurating furnace. If the performance testing cannot be performed when the production rate is equal to or greater than 90 percent of the production rate capacity of the furnace, the owner or operator may complete testing at a lower production rate if they receive approval from the delegated authority. An owner or operator selecting this option must install and operate continuous parameter monitoring systems (CPMS) to monitor the parameters specified in 40 CFR 63.9631(g). An owner or operator must take corrective action when an established operating limit is exceeded.

The initial performance testing must be completed within 180 calendar days of the compliance date specified in 40 CFR 63.9583(f) for existing sources or within 180 calendar days of startup for new sources, using EPA Methods 29 or 30B in 40 CFR part 60, appendix A–8 or the VCS ASTM D6784–16, *Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method).* The performance tests must be repeated at least twice per 5-year permit term.

The second option by which an owner or operator may demonstrate compliance is through the installation and operation of CEMS for Hg. The CEMS must be installed, calibrated, maintained, and operated in accordance with the procedures specified in 40 CFR 63.9631(j). An owner or operator selecting this approach is not required to establish operating limits, install and operate CPMS, or complete the initial and periodic performance testing for Hg emissions.

As discussed in section III.A.2 of this preamble, the final rule includes an option for adjusting the carbon injection rate based on the taconite pellet production level. The facility has the option of establishing operating limits for different production rates by conducting performance tests at the maximum, minimum and median taconite pellet production rates to develop a relationship between carbon injection rate and taconite pellet production rate or by adjusting the ACI rate based on Hg emissions data collected by CEMS. Facilities that elect to adjust the carbon injection rate based on taconite production levels will have lower compliance costs due to lower annual consumption of activated carbon.

Each owner or operator must prepare a preventive maintenance plan and keep records of calibration and accuracy checks of the CPMS or CEMS to document proper operation and maintenance of all monitoring systems used to demonstrate compliance with the applicable Hg standard.

B. Revised Emission Standards for HCl and HF

1. What did we propose for the Taconite Iron Ore Processing source category?

As described in the May 15, 2023, proposal (88 FR 30917), we proposed to revise the numerical emission limits for HCl and HF, pursuant to CAA section 112(d)(6). CAA section 112(d)(6) requires the EPA to review standards promulgated under CAA section 112 and revise them ''as necessary (taking into account developments in practices, processes, and control technologies)'' no less often than every 8 years; we refer to such action under CAA section 112(d)(6) as a ''technology review.'' The EPA previously completed a technology review for the Taconite Iron Ore Processing source category in 2020 (85 FR 45476; July 28, 2020). In the May 15, 2023, proposal, we proposed to revise the HCl and HF standards based on new information we obtained in response to the 2022 information collection concerning emissions of these pollutants from the source category. For existing indurating furnaces, we proposed emissions standards of 4.4×10^{-2} lb/LT for HCl and 1.2×10^{-2} lb/LT for HF. For new indurating furnaces, we proposed emission standards of 4.4×10^{-4} lb/LT for HCl and 3.3×10^{-4} lb/LT for HF. We proposed to require that owners or operators demonstrate compliance through initial and periodic performance testing (completed at least twice per 5-year permit term), establishing operating limits for each control device used to comply with the HCl and HF standards, and installing and operating continuous parameter monitoring systems (CPMS) to ensure continuous compliance with the standards.

2. What comments did we receive on the proposed revised HCl and HF emission standards, and what are our responses?

Comment: We received comments and data from industry identifying errors in the emissions data for the Tilden and Hibbing indurating furnaces submitted to the EPA in response to the CAA section 114 information request sent to the taconite facilities in 2022. For the Tilden stack test report, industry confirmed the units of measure were incorrectly listed in the stack test report submitted by industry as ''pounds per ton'' instead of ''pounds per long ton'' of taconite pellets produced. Commenters confirmed the units of measure should be ''pounds per long ton.'' For Hibbing, the commenters identified one transcription error in the HCl emissions data for one of the four emission stacks.

Response: In response to these comments, the EPA reviewed all stack test runs for the seven furnaces that completed HCl and HF stack testing pursuant to the 2022 CAA section 114 information request. We confirmed there was a transcription error in HCl emissions for the first run of the stack testing completed on the Hibbing furnace. Since the emissions data for Hibbing were included in the dataset used to calculate the proposed HCl emission limit, we recalculated the emission limit for HCl using the revised data. As a result of the changes to the Hibbing emissions data, the numerical emission standard for HCl for existing sources was revised from the proposed 4.4×10^{-2} lb/LT to the 4.6×10^{-2} lb/LT limit we are finalizing in this action. The revisions to the emissions data do not impact the numerical limit for HCl for new sources or the numerical limits for HF for new and existing sources. Therefore, the proposed HCl standard for new sources of 4.4×10^{-4} lb/LT and the HF standards for new and existing sources of 3.3×10^{-4} lb/LT and 1.2×10^{-2} lb/LT, respectively, are finalized without change.

The EPA revised the units of measure for the Tilden HCl and HF emission data based on the comments we received from industry. As we explained in the proposal, the HCl and HF emissions data for the Tilden furnace are not used to calculate the emission limits for HCl and HF because Tilden's furnaces use dry electrostatic precipitators (ESP). In the proposal, we stated that we expect Tilden's two indurating furnaces would be able to meet the HF limit for existing furnaces without adding any air pollution control devices but that we expect Tilden would be required to add air pollution control devices to meet the proposed HCl emission standard. Although the revised emission rates for Tilden are slightly lower than the emissions rates used for the proposal, we expect that Tilden's furnaces would still need to add air pollution controls to meet the HCl emission standard we are finalizing for existing furnaces. As explained in the previous paragraph, the EPA is finalizing the HCl emission standard of 4.6×10^{-2} lb/LT for existing sources. To comply with the HCl emission standard, Tilden must reduce HCl emissions by 76 percent (compared to 79 percent HCl reduction we estimated at proposal) and the HCl emissions reduction for the final rule is 683 tpy (compared to a 713 tpy reduction we estimated at proposal). Our revised total capital cost estimate for HCl controls (dry sorbent injection) is $1.1 million and our revised annual cost estimate is $1.4 million. The revised cost effectiveness is $2,040 per ton of HCl removed, which is a level of cost effectiveness that is acceptable for HCl and would also likely be acceptable for any other HAP. The revised emissions data, numerical limits, and cost estimates prepared for the final rule are documented in the memorandum, *Final Revised Technology Review of Acid Gas Controls for Indurating*

Furnaces in the Taconite Iron Ore Processing Source Category, which is available in the docket for this action.

Comment: Multiple commenters were supportive of replacing PM as a surrogate for HCl and HF emissions and supported the proposed numerical emission limits for HCl and HF. One commenter said the PM limit was not a valid surrogate for emissions of HCl and HF and argued the EPA should set HCl and HF limits under the provisions of CAA section 112(d)(2) and (3). However, other commenters from industry disagreed with our proposal and said the existing standards based on PM as a surrogate for acid gases should not be changed. These commenters asserted that the EPA lacked the authority to revise the existing HCl and HF standards because the EPA had not shown that technological developments have occurred that would lower emissions of acid gases nor shown that revisions are necessary, as required by CAA section 112(d)(6). The commenters stated that new emissions data does not qualify as a development under CAA section 112(d)(6) and that the language in CAA section 112(d)(6) focuses on actual control measures and requires the EPA to update an existing emissions standard only if improvements in control measures occur and the improvements in control measures warrant a revision. The commenters added that PM is still recognized as a proper surrogate for HAP emissions and the revised standards are unnecessary because they impose a significant financial burden on taconite iron ore processing plants without reducing risks to the public health and the environment.

Response: The EPA agrees that revising the emission limits for HCl and HF is appropriate for the reasons explained in this discussion, below, and in the proposal preamble (88 FR 30926). We disagree that the EPA lacks authority to revise the existing standards for HCl and HF. When the NESHAP for the Taconite Iron Ore Processing source category was first developed, PM emission limits were used as a surrogate for HCl and HF. The decision to use the PM standards as a surrogate for HCl and HF emissions was based on an analysis of the HCl, HF, and PM emissions data that the EPA possessed at the time of promulgation of the initial NESHAP for the Taconite Iron Ore Processing source category in 2003 (68 FR 61868; October 30, 2003). That data indicated there was a correlation between acid gas and PM emissions. We note, however, that the use of PM as a surrogate for HCl and HF and the corresponding PM emission limit were based on a limited dataset because only three furnaces conducted PM emissions tests concurrently with the HCl and HF tests. As part of the 2022 CAA section 114 information request, the EPA sought emissions data from Taconite Iron Ore Processing facilities, including stack testing for PM, HCl, and HF emissions from seven indurating furnaces located at six taconite facilities. The data received in response to the 2022 CAA section 114 information request are presented in the memorandum, *Final Emissions Data Collected in 2022 for Indurating Furnaces Located at Taconite Iron Ore Processing Plants,* which is available in the docket for this action. The 2022 dataset is not only more robust than the limited dataset available in 2003 but also more representative of current conditions since some of the control devices used on the furnaces at the time of the 2003 rulemaking have changed since that time. For example, the Keetac plant has since replaced the multicyclones on their indurating furnace with venturi scrubbers and the Tilden plant replaced a wet ESP on one stack with a dry ESP. Based on this new data, we determined it was more appropriate to directly regulate the HAP of concern than to use a surrogate. Our analysis of the 2022 data and our review of available air pollution controls for acid gases indicates that the controls we expect will be necessary to meet the numerical standards for HCl and HF are available and cost-effective. As we explained in the proposal (88 FR 30926), the new data received in response to the 2022 CAA section 114 information request showed that indurating furnaces using wet scrubbers achieve better control of HCl and HF than furnaces using dry ESP.

We disagree with commenter that we lack the authority to revise standards pursuant to CAA section 112(d)(6) absent a showing that the revisions would reduce risk. CAA section 112(d)(6) requires the EPA to review and revise as necessary emission standards taking into account developments in practices, processes, and control technologies. This provision does not require the EPA to consider risk. We agree that the EPA has the discretion to consider cost when considering the appropriate level of control under CAA section 112(d)(6). The EPA identified dry sorbent injection (DSI) and wet scrubbers as a feasible control options and estimated the associated costs. We concluded that DSI is the lowest cost option for the indurating furnaces located at the Tilden plant. Based on this analysis, the EPA concluded the costs to comply with the numerical limits for HCl were justified and cost-effective and do not impose a significant financial burden on industry. The cost effectiveness was estimated to be $2,040 per ton of HCl removed, which is within the range the EPA has previously considered to be a cost-effective level of control for many HAP. Based on the 2022 emissions data, add on air pollution controls are not required to meet the HF emission limit. The standards we are finalizing in this action ensure HCl and HF emissions from all indurating furnaces in the source category are controlled to the same extent as the best performing indurating furnaces in the source category.

Comment: Industry commenters stated there is no basis for changing the way HCl and HF emissions are regulated, that the EPA did not explain why PM cannot be used as a surrogate for HCl and HF emissions, and that if revised standards were needed, they should be based on the subcategories established in the Taconite Iron Ore Processing NESHAP in 2003. The commenters stated that the EPA should make determinations on whether new standards are necessary for each subcategory and then should base any new standards for each subcategory on emission data for the furnaces within that subcategory. The commenters acknowledged that CAA section 112(d)(6) authorizes the EPA to review and revise as necessary the emission standards every 8 years, but they said the statute does not permit the EPA to develop new standards ignoring the existing subcategories. The commenters argued the Tilden facility processes a different type of taconite ore (*i.e.,* hematite instead of magnetite) than the other facilities and therefore the furnaces at this facility should remain in a separate subcategory from the furnaces at the other facilities (as was the case when the EPA established the PM standards in the 2003 NESHAP). The commenters noted that a subcategory was established for grate kilns processing hematite ore because of differences in the ore and furnace, including different air flow direction and rates, the perpetual motion of the pellets inside the kiln, fineness of the hematite ore, tendency for the hematite pellets to break, and production of fluxed pellets that use limestone/dolomite containing chloride. For furnaces that process magnetite, the commenters argued that limits for HCl and HF are not needed and would result in unnecessary compliance costs without health and environmental benefits.

Response: We disagree with the industry commenters' assertion that the EPA should extend the subcategorization for PM standards used in the 2003 rulemaking and set HCl and HF limits only for grate kilns processing hematite ore. When the NESHAP for the Taconite Iron Ore Processing source category was initially developed, indurating furnaces were identified as significant sources of HCl and HF emissions. The NESHAP promulgated in 2003 established limits, as required under CAA section 112(d), for all indurating furnaces. The decision to use the PM standards as a surrogate for HCl and HF emissions was based on very limited HCl, HF, and PM emissions data available and evaluated for the 2003 rulemaking. As we explained in the response to the previous comment, in this action, we have determined it is more appropriate to directly regulate the HAP of concern (*i.e.,* HCl and HF) than to use a surrogate, using the more robust 2022 dataset now available to us. The data collected for this rulemaking are presented in the memorandum, *Final Emissions Data Collected in 2022 for Indurating Furnaces Located at Taconite Iron Ore Processing Plants,* which is available in the docket for this action.

We disagree with commenters' assertion that emission limits for acid gases should be established using the existing subcategories for PM and that HCl and HF standards are not necessary for furnaces that process magnetite ore. The EPA found in the 2003 NESHAP final rule that HCl and HF are emitted by all indurating furnaces and established standards for all types of indurating furnaces in the Taconite Iron Ore Processing source category, including those indurating furnaces that process magnetite ore. Indeed, the emissions data collected in response to the 2022 CAA section 114 information request demonstrate that indurating furnaces processing magnetite ore emit measurable levels of HCl and HF even after control by wet scrubbers. HCl and HF are formed in indurating furnaces due to the presence of chlorides and fluorides in the raw materials used to form the greenballs (*i.e.,* unfired taconite pellets) that are fed into the indurating furnaces. While some of the chlorides and fluorides in the raw materials come from the ore, pellet additives, such as dolomite and limestone, are also a source of HCl and HF emissions. These additives are routinely used by all taconite plants, including those that process magnetite ore. Although the commenters suggested plants processing hematite ore using grate-kilns should be considered a separate subcategory when considering acid gas emissions, the commenters provided no data demonstrating a significant difference in the chloride and fluoride content of the two types of ores. Nor did they provide any explanation or data to support their assertion that differences in the design of the indurating furnace impact HCl and HF emissions. The data pertaining to indurating furnaces processing magnetite ore that was collected in response to the 2022 CAA section 114 information request does not show a significant difference in acid gas emissions between straight-grate and grate kiln indurating furnaces.

Pursuant to CAA section 112(d)(1), the Administrator "may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing" standards. However, as we have discussed in previous Agency actions, the CAA does not mandate that the EPA create subcategories. See, *e.g., National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units* (77 FR 9304, 9378; February 16, 2012) ("2012 Mercury and Air Toxics Final Rule"). In addition, the Agency may create subcategories for the purpose of regulating specific HAP, while declining to create subcategories more broadly. In the 2012 Mercury and Air Toxics Final Rule, we explained the Agency's position that any basis for subcategorization (*i.e.,* class, type, or size) typically must be related to an effect on HAP emissions that is due to the difference in class, type, or size of the sources. We further explained that "[e]ven if we determine that emissions characteristics are different for units that differ in class, type, or size, the Agency may still decline to subcategorize if there are compelling policy justifications that suggest subcategorization is not appropriate" (77 FR 9378). In the 2012 Mercury and Air Toxics Final Rule, we determined it was appropriate to subcategorize coal-fired boilers for purposes of regulating Hg emissions based on differences in Hg emissions between two types of coal-fired boiler subcategories. We also determined that for all other HAP, the data did not show any difference in HAP emission levels, and we declined to set separate emission standards for the two types of coal-fired boilers for other HAP.

In this final rule, we are retaining the separate PM emission limits established in the 2003 final rule for indurating furnaces processing magnetite and hematite. Based on the data available, we continue to believe it is appropriate to retain these separate PM emission standards because hematite is a finer grained ore than magnetite, and processing of hematite in an indurating furnace results in higher PM emissions than processing magnetite. However, we are declining to subcategorize taconite indurating furnaces for purposes of regulating Hg or acid gas emissions. As explained previously, pursuant to CAA section 112(d)(1), the EPA has the discretion to subcategorize sources for the purpose of setting emission standards under CAA section 112, but is not required to do so. As we also explained, where the EPA elects to subcategorize sources, we typically do so for the purpose of setting standards for specific HAP where the basis for the subcategorization is related to an effect on HAP emissions that is due to a difference in class, type, or size of the sources. The differences in emissions of HCl and HF among taconite indurating furnaces are largely the result of differing controls utilized by sources rather than a result of the class, type, or size of the indurating furnaces themselves. Therefore, we conclude that the differences in HCl and HF emissions are not due to differences in the class, type, of size of taconite indurating furnaces. As a result, we do not believe it is appropriate to subcategorize taconite indurating furnaces for the purpose of regulating Hg, HCl, or HF emissions and are declining to do so in this final rule.

Based on the data available, the EPA proposed to set HCl and HF emission standards that apply to all indurating furnaces. In this action, we are finalizing emission standards for HCl and HF as discussed in section III.B.1 of this preamble. While the HCl emission standard for existing furnaces differs from what we proposed for the reasons explained in section III.B.2 of this preamble, we continue to believe it is appropriate to set numerical emission standards for HCl and HF based on the 2022 ICR data rather than to continue to rely on PM standards as a surrogate for these pollutants. While we expect that most indurating furnaces will be able to meet the revised HCl and HF limits using existing air pollution controls, the new performance testing and parametric monitoring requirements are necessary to ensure continuous compliance with the HCl and HF emission standards. The

PM testing and monitoring requirements in the current NESHAP designed to ensure compliance with the PM emission standards, which will remain in place as surrogates for non-Hg metal HAP, are not sufficient to demonstrate compliance with the HCl and HF emission standards. Each owner and operator must complete performance testing, establish operating limits for each control device used to control HCl and HF, and monitor the appropriate parameters to demonstrate the control device is operating in a manner that ensures compliance with the HCl and HF emission standards. Performance testing must be completed at least twice per 5-year permit term and within 180 days of startup of new furnaces.

Comment: Industry commenters asserted the data used to develop the numerical standards for HCl and HF was too limited to reflect the operational and seasonal variability in the HCl and HF emissions. They stated that several factors influence the HCl and HF emissions and that the emissions data received in response to the 2022 CAA section 114 information request covers too short of a time period to be representative of the acid gas emissions from indurating furnaces. The commenters noted that HCl and HF emissions are driven by the chloride or fluoride content in the iron ore and that the limited dataset does not account for the full range of variability in the chlorine and fluorine content of raw materials. They stated that the raw materials vary throughout a taconite mine, producing raw materials with different compositions and characteristics that are not reflected in the 2022 CAA section 114 information request data. The commenters recommended the HCl and HF limits be based on a more representative dataset collected over a longer period of time that accounts for raw material variation as well as seasonal and operational variation. The commenters stated that because the proposed limits are based on a limited dataset that does not fully account for operational variability, the proposed HCl and HF emission limits should not be finalized and they recommended that the PM standards in the current NESHAP continue to be used as a surrogate for acid gas emissions.

Response: The method used to calculate the proposed numeric emission limits for HCl and HF for new and existing taconite indurating furnaces has been used for several years to set numerical limits for other source categories and is an appropriate methodology that accounts for variability in the emissions between different furnaces and different plants and accounts for some variability in the chloride and fluoride content of the ore and pellet additives used at different facilities because it includes data from two different types of indurating furnaces (straight grate furnaces and grate kiln furnaces) at five different taconite facilities. We used the emissions data from the six indurating furnaces currently using wet scrubbers to calculate a UPL. The UPL approach encompasses all the data point-to-data point variability within the sample set (*i.e.,* all of the emissions data from the six indurating furnaces equipped with wet venturi scrubbers), which consisted of 21 individual data points. The UPL was calculated as the mean of the 21 data points plus a factor that accounts for the variability within the dataset. The UPL represents the value which one can expect the mean of a specified number of future observations (*e.g.,* 3-run average) to fall below at a specified level of confidence based upon the results of an independent sample from the same population. We used a 99-percent level of confidence to calculate the UPL, which means that a facility that uses the same or similar type of air pollution control device(s) has one chance in 100 of exceeding the emission limit. A prediction interval for a single future observation (or an average of several test observations) is an interval that will, with a specified degree of confidence, contain the next (or the average of some other pre-specified number of) randomly selected observation(s) from a population. The UPL estimates what the upper bound of future values will be based upon present or past background samples taken. While larger datasets are always preferable, numerical emission limits are often based on data from a single stack test event. For additional information on the methodology used to develop the numerical emission standards for HCl and HF for the final rule, please see the memorandum, *Final Revised Technology Review of Acid Gas Controls for Indurating Furnaces in the Taconite Iron Ore Processing Source Category.* A copy of this document is available in the docket for this action.

3. What are the revised standards for HCl and HF and how will compliance be demonstrated?

We are finalizing numerical emission limits for HCl and HF, pursuant to CAA section 112(d)(6). We are finalizing as proposed the numerical emission limit for HCl for new indurating furnaces. We are finalizing a numerical emission limit for HCl for existing indurating furnaces which differs from the limit proposed because the final limit reflects a revision to the emissions data for the Hibbing facility, as discussed in section III.B.2 of this preamble. We are finalizing as proposed the numerical emission limits for HF for new and existing indurating furnaces. For existing indurating furnaces, we are finalizing an HCl emission limit of 4.6×10^{-2} lb/LT and are finalizing an HF emission limit of 1.2×10^{-2} lb/LT. For new indurating furnaces, we are finalizing an HCl emission limit of 4.4×10^{-4} lb/LT and are finalizing an HF emission limit of 3.3×10^{-4} lb/LT. Further discussion of the HCl and HF emission standards and the methodology used to develop the emission standards, as well as a discussion of costs, may be found in the memorandum, *Final Revised Technology Review of Acid Gas Controls for Indurating Furnaces in the Taconite Iron Ore Processing Source Category,* which is available in the docket for this action.

We are also finalizing as proposed the requirement to complete performance testing for HCl and HF using EPA Method 26A and to establish operating limits for each control device used to comply with the HCl and HF standards, in accordance with the amended provisions of 40 CFR 63.9622. The final rule clarifies that the owner or operator must perform performance testing when the pellet production rate is equal to or greater than 90 percent of the capacity of the indurating furnace. If the performance testing cannot be performed at or above 90 percent of capacity of the indurating furnace, the owner or operator may complete testing at a lower production rate if they receive approval from the delegated authority. The owner or operator must install and operate CPMS in accordance with the requirements of 40 CFR 63.9633 and must prepare a preventive maintenance plan and keep records of calibration and accuracy checks of the CPMS to document proper operation and maintenance of each monitoring system. An owner or operator must take corrective action when an established operating limit is exceeded. The owner or operator must complete the initial performance tests within 180 calendar days of the compliance date for existing furnaces, or within 180 calendar days of startup for new furnaces. The performance tests must be repeated at least twice per 5-year permit term.

C. What other amendments are we finalizing?

1. Requirement To Complete Performance Testing Within 7 Calendar Days

The EPA proposed amendments to the performance testing provisions that would require the owner or operator to complete a performance test on a source within 7 calendar days of initiating that performance test. This provision was included for the existing performance testing for PM, as well as for the proposed new performance testing for Hg, HCl, and HF. We received one comment that resulted in changes to the proposed requirements. The comment and our response are summarized below.

Comments: Industry commenters opposed the proposed requirement that all performance testing be completed within 7 calendar days because some emission sources have multiple stacks and testing of multiple stacks could require more than 7 days to complete. They also stated that unanticipated shutdowns due to process upsets may prevent tests from being completed within 7 days. The commenters recommended that the EPA allow facilities to notify the Administrator when a longer time frame is needed but asserted that facilities should not be required to obtain approval if more than 7 calendar days are needed to complete performance testing.

Response: We consider the 7 calendar day period to complete all performance testing to be reasonable based on our previous experience with performance testing at industrial facilities. We believe it is unlikely that a facility would be unable to complete the required performance testing within a 7 calendar day timeframe. However, we acknowledge the commenters' concerns that unanticipated shutdowns can occur due to equipment failures or process upsets. To address such circumstances, we included the phrase ''to the extent practicable'' in the final rule. We have finalized the proposed requirement that performance tests be completed within 7 calendar days of the date on which the first test run was started. However, we agree with the commenters' suggestion that owners and operators be required to notify the Administrator when a performance test cannot be completed within 7 calendar days. In the final rule, we revised the proposed language in 40 CFR 63.9620(b)(2), 63.9620(k)(2), and 63.9630(b) to require facilities that will not be able to complete performance tests within 7 calendar days to notify the Administrator within 24 hours of making the determination that they will not be able to do so.

2. Amendments to the Electronic Reporting Requirements

We are also finalizing as proposed changes to the electronic reporting requirements found in 40 CFR 63.9641(c) and 40 CFR 63.9641(f)(3) to reflect new procedures for reporting CBI, including adding an email address that an owner or operator may use to electronically submit compliance reports containing CBI to the OAQPS CBI Office. We received no comments on these proposed amendments.

D. What are the effective and compliance dates for the mercury, HCl, and HF emission standards?

The revisions to the MACT standards promulgated in this action are effective on March 6, 2024. For all affected sources that commence construction or reconstruction before May 15, 2023, we are finalizing, as proposed, that an owner or operator must comply with the new Hg emission standard and revised HCl and HF standards no later than 3 years after the effective date of the final rule. For all affected sources that commenced construction or reconstruction on or after May 15, 2023, we are finalizing, as proposed, that owners and operators comply with provisions by the effective date of the final rule or upon startup, whichever is later. For existing sources, CAA section 112(i)(3) requires compliance ''as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard'' subject to certain exemptions further detailed in the statute.[4] In determining what compliance period is as ''expeditious as practicable,'' we examine the amount of time needed to plan and construct projects and change operating procedures. Since some existing sources may need to install new add-on controls to comply with the Hg, HCl, and/or HF standards, we determined that a period of 3 years is appropriate to allow owners and operators time to plan, design, construct, begin operating the new add-on controls, and conduct performance testing.

IV. Summary of Cost, Environmental, and Economic Impacts

A. What are the affected sources?

The Taconite Iron Ore Processing NESHAP applies to the owner or operator of a taconite iron ore processing plant that is (or is part of) a major source of HAP emissions. A taconite iron ore processing plant is any facility engaged in separating and concentrating iron ore from taconite ore to produce taconite pellets. Taconite iron ore processing includes the following processes: liberation of the iron ore by wet or dry crushing and grinding in gyratory crushers, cone crushers, rod mills, and ball mills; concentration of the iron ore by magnetic separation or flotation; pelletizing by wet tumbling with a balling drum or balling disc; induration using a straight grate or grate kiln indurating furnace; and finished pellet handling. 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, or any combination of HAP at a rate of 22.68 megagrams (25 tons) or more per year from all emission sources at the plant site. There are currently seven major sources subject to the Taconite Iron Ore Processing NESHAP that are operating in the United States with six located in Minnesota and one located in Michigan. One additional major source located in Michigan, Empire Mining, is subject to the Taconite Iron Ore Processing NESHAP and has a permit to operate but has been indefinitely idled since 2016.

B. What are the air quality impacts?

To meet the Hg emission limits we anticipate that five of the taconite iron ore processing plants would likely need to install additional controls on their indurating furnaces. To meet the HCl and HF emission limits, we anticipate that one additional taconite iron ore processing plant would likely need to install additional controls on their indurating furnaces. We estimate that the installation of such controls will reduce Hg emissions by 247 pounds per year (0.12 tpy) and HCl and HF emissions by 683 tpy and 36 tpy, respectively.

Indirect or secondary air emissions impacts are impacts that would result from the increased electricity usage associated with the operation of control devices (*e.g.,* increased secondary emissions of criteria pollutants from power plants). Energy impacts consist of the electricity and steam needed to operate control devices and other equipment. As explained in the memorandum, *Development of Impacts for the Final Amendments to the NESHAP for Taconite Iron Ore Processing,* which is available in the docket for this action, we find that the secondary air emissions impacts of this

---

[4] *Association of Battery Recyclers* v. *EPA,* 716 F.3d 667, 672 (D.C. Cir. 2013) (''Section 112(i)(3)'s 3-year maximum compliance period applies generally to any emission standard . . . promulgated under [section 112]'' (brackets in original)).

action are minimal. The memorandum includes a detailed discussion of our analysis of emissions reductions and potential secondary impacts.

This rule is expected to limit emissions of directly emitted $PM_{2.5}$, which will in turn reduce ambient concentrations of $PM_{2.5}$ and in turn benefit public health. Though EPA neither quantified nor monetized these benefits, we anticipate reducing $PM_{2.5}$ concentrations will reduce the incidence or premature death, non-fatal heart attacks, cases of aggravated asthma, lost days of work and school and other adverse effects (U.S. EPA, 2022).[5] EPA has generated benefit per ton estimates for directly emitted $PM_{2.5}$ reductions from the taconite sector valued at $60,600/ton (2016$).[6] In addition, there are estimates for secondarily-formed $PM_{2.5}$ from reductions in SO_2 emissions valued at $32,800/ton (2016$). However, EPA did not conduct a comprehensive benefit-cost analysis for this rulemaking. This rule is also expected to reduce emissions of Hg. Methylmercury (MeHg), which is formed by microbial action in the top layers of sediment and soils, after mercury has precipitated from the air and deposited into waterbodies or land, is known to cause a number of adverse effects. Though not quantified here, these effects include IQ loss measured by performance on neurobehavioral tests, particularly on tests of attention, fine motor-function, language, and visual spatial ability.

C. What are the cost impacts?

We estimate the total capital and annualized costs of this final rule for existing sources in the Taconite Iron Ore Processing source category will be approximately $106 million and $68 million per year, respectively. The annual costs are based on operation and maintenance of added control systems. Although this action also finalizes standards for new sources, we are not aware of any new sources being constructed now or planned for the future. No new indurating furnaces have been constructed, reconstructed or modified in more than a decade and the domestic demand for taconite pellets has decreased over the past several decades caused by the increasing use of electric arc furnaces.[7] Consequently, we did not estimate any cost impacts for new sources. The memorandum, *Development of Impacts for the Final Amendments to the NESHAP for Taconite Iron Ore Processing,* includes details of our cost assessment, expected emission reductions and estimated secondary impacts. A copy of this memorandum is available in the docket for this action.

D. What are the economic impacts?

The EPA assessed the potential economic impacts of this action by comparing the expected annual cost for operating the air pollution control devices to the total sales revenue for the ultimate owners of affected facilities. The expected annual cost is $10.2 million (on average) for each facility that needs air pollution controls to comply with the standards, with an estimated nationwide annual cost of $61 million per year. The six affected facilities are owned by two parent companies (U.S. Steel and Cleveland-Cliffs, Inc.). Neither parent company qualifies as a small business, and the total costs associated with this final rule are expected to be less than 1 percent of annual sales revenue per ultimate owner.

The EPA also modeled the economic impacts of the final rule using two standard partial equilibrium economic models: one for taconite iron ore pellets and one for steel mill products. The EPA linked these two partial equilibrium models by specifying interactions between supply and demand in both markets and solving for changes in prices and quantity across both markets simultaneously. These models use baseline economic data from 2019 to project the impact of the final rule on the market for taconite iron ore pellets and steel mill products. The models allow the EPA to project facility- and market-level price and quantity changes for taconite iron ore pellets and market-level price and quantity changes for steel mill products, including changes in imports and exports in both markets. The models project a 0.28 percent fall in the quantity of domestically produced taconite iron ore pellets along with a 0.63 percent increase in their price. The models also project a 0.02 percent fall in the quantity of domestically produced steel mill products along with an 0.01 percent increase in their price. Details of our economic impact estimates for sources in the Taconite Iron Ore Processing source category may be found in the document, *Economic Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Amendments* (EIA), which is available in the docket for this action.

E. What analysis of environmental justice did we conduct?

Consistent with the EPA's commitment to integrating environmental justice (EJ) into the Agency's actions, and following the directives set forth in multiple executive orders, the EPA evaluated the impacts of this action on communities with EJ concerns. Overall, we found that in the population living in close proximity (within 10 kilometers (km)) of facilities, the following demographic groups were above the national average: White, Native American, and people living below the poverty level. The EPA defines EJ as ''the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.'' [8] The EPA further defines fair treatment to mean that ''no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies.''

For the Taconite Iron Ore Processing source category, the EPA examined the potential for EJ concerns by conducting a proximity demographic analysis for the eight existing taconite iron ore processing plants (seven operating plants and one indefinitely idled). The proximity demographic analysis is an assessment of individual demographic groups in the total population living within 10 km and 50 km of the facilities. The EPA compared the data from this analysis to the national average for each of the demographic groups. Since the taconite iron ore processing facilities are very large, a radius of 10 km was used as the near facility distance for the proximity analysis. A distance closer than 10 km does not yield adequate population size for the results. A summary of the proximity demographic assessment was included in Table 5 in the proposal for this rulemaking (88 FR 30931; May 15, 2023). The results show that for the population living within 10

---

[5] U.S. EPA, 2022. *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits.* Office of Air and Radiation, Research Triangle Park, NC.

[6] U.S. EPA (2023). Technical Support Document Estimating the Benefit per Ton of Reducing Directly-Emitted $PM_{2.5}$, $PM_{2.5}$ Precursors and Ozone Precursors from 21 Sectors. Research Triangle Park, NC: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Health and Environmental Impact Division. Available at: *https://www.epa.gov/system/files/documents/2021-10/source-apportionment-tsd-oct-222021_0.pdf.*

[7] U.S. EPA, 2024. *Economic Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Amendments.* Office of Air and Radiation, Research Triangle Park, NC.

[8] *https://www.epa.gov/environmentaljustice.*

km of the eight facilities, the following demographic groups were above the national average: White (93 percent versus 60 percent nationally), Native American (0.8 percent versus 0.7 percent nationally), and people living below the poverty level (15 percent versus 13 percent nationally). For two facilities (the UTAC and Minntac facilities), the percentage of the population living within 10 km that is Native American (1.9 percent and 2.3 percent) was more than double the national average (0.7 percent). For four facilities (Keetac, Hibbing, Minorca, and Minntac) the percentage of the population living within 10 km that is low-income is above the national average. The results of the proximity analysis are in the technical report, *Analysis of Demographic Factors For Populations Living Near Taconite Iron Ore Processing Source Category Operations,* which is available in the docket for this action.

This action sets new standards for Hg and revised standards for HCl and HF that will reduce the annual emissions of these HAP from taconite facilities. The Hg standards will reduce the health, environmental and cultural impacts of Hg identified by tribes in their comments by requiring the five taconite facilities (UTAC, Keetac, Hibbing, Minorca, and Minntac) that have nearby Native American populations and low-income populations above the national averages to reduce Hg emissions by up to 247 pounds per year (0.12 tpy). The emission limits must be met at all times (including periods of startup, shutdown, and malfunctions) and compliance must be demonstrated through monitoring of control device operating parameters and either periodic testing or CEMS.

V. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a ''significant regulatory action'' as defined in Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket. The EPA prepared an economic analysis of the potential impacts associated with this action. This analysis is summarized in section IV.D of this preamble and in the document *Economic Impact Analysis for the Final National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Amendments,* available in Docket ID No. EPA–HQ–OAR–2017–0664.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2050.10, OMB Control Number 2060–0538. You can find a copy of the ICR in the docket for this action, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

In this action, we are finalizing changes to the reporting and recordkeeping requirements for the Taconite Iron Ore Processing NESHAP by incorporating reporting and recordkeeping requirements for the new MACT standards for Hg and the revised emission standards for HCl and HF.

Respondents/affected entities: Owners or operators of taconite iron ore plants that are major sources, or that are located at, or are part of, major sources of HAP emissions.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart RRRRR).

Estimated number of respondents: On average over the next 3 years, approximately seven existing major sources will be subject to these standards. It is also estimated that no additional respondent will become subject to the emission standards over the 3-year period.

Frequency of response: The frequency of responses varies depending on the burden item.

Total estimated burden: The average annual burden to industry over the next 3 years from the new recordkeeping and reporting requirements is estimated to be 1,580 hours per year. Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: The annual recordkeeping and reporting costs for all facilities to comply with all the requirements in the NESHAP is estimated to be $185,000 per year. The average annual recordkeeping and reporting cost for this rulemaking is estimated to be $26,500 per facility per year. The operation and maintenance costs are estimated to be $18 million per year.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. The Agency confirmed through responses to a CAA section 114 information request that there are only seven taconite iron ore processing plants currently operating in the United States and that these plants are owned by two parent companies that do not meet the definition of small businesses, as defined by the U.S. Small Business Administration.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local, or Tribal governments or the private sector.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the National Government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have Tribal implications as specified in Executive Order 13175. The Executive Order defines Tribal implications as ''actions that have substantial direct effects on one or more Indian Tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.'' The amendments in this action would not have a substantial direct effect on one or more tribes, change the relationship between the Federal Government and tribes, or affect the distribution of power and responsibilities between the Federal Government and Indian Tribes. Thus, Executive Order 13175 does not apply to this action.

Although this action does not have Tribal implications as defined by Executive Order 13175, consistent with the *EPA Policy on Consultation and Coordination with Indian Tribes,* the EPA consulted with Tribal officials during the development of this action. On January 12, 2022, the EPA's Office of Air and Radiation held a Tribal consultation meeting with the Fond du Lac Band of Lake Superior Chippewa Reservation and the Leech Lake Band of Ojibwe Reservation to discuss the EPA's 2022 CAA section 114 information request and to ensure that the views of tribes were taken into consideration in the rulemaking process in accordance with the *EPA Policy on Consultation and Coordination with Indian Tribes (May 4, 2011)* and the *EPA Policy on Consultation and Coordination with Indian Tribes: Guidance for Discussing Tribal Treaty Rights (February 2016).* A summary of the meeting may be found in the document, *Consultation with the Fond du Lac Band of Lake Superior Chippewa and the Leech Lake Band of Ojibwe regarding Notice of Proposed Rulemaking for the National Emission Standards for Hazardous Air Pollutants for Taconite Iron Ore Processing Amendments on January 12, 2022,* which is available in the docket for this action. In addition, the EPA's staff attended several meetings hosted by the Minnesota Pollution Control Agency (MPCA), along with representatives from Tribal Nations, MPCA, the Michigan Attorney General's Office, the Minnesota Attorney General's Office, Earthjustice, and the Michigan Department of Environment, Great Lakes, and Energy, to discuss concerns related to HAP emissions from taconite iron ore processing facilities. The EPA also received letters from representatives of the Leech Lake Band of Ojibwe and the Fond du Lac Band of Lake Superior Chippewa expressing concerns of these Tribal Nations due to HAP emissions from the taconite iron ore processing facilities. Copies of these letters, as well as the EPA's responses to them, are available in the docket for this action.

G. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This action involves technical standards. Therefore, the EPA conducted searches for the Taconite Iron Ore Processing NESHAP through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). We also conducted a review of VCS organizations and accessed and searched their databases. We conducted searches for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 2F, 2G, 3, 3A, 3B, 4, 5, 5D, 17, 26A, 29 and 30B. During the VCS search, if the title or abstract (if provided) of the VCS described technical sampling and analytical procedures that are similar to the EPA's reference method, the EPA ordered a copy of the standard and reviewed it as a potential equivalent method. We reviewed all potential standards to determine the practicality of the VCS for this rule. This review requires significant method validation data that meet the requirements of EPA Method 301 for accepting alternative methods or scientific, engineering, and policy equivalence to procedures in the EPA referenced methods. The EPA may reconsider determinations of impracticality when additional information is available for any particular VCS.

No VCS were identified for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 2F, 2G, 3, 3A, 4, 5, 5D, 17 or 26A. One VCS was identified as an acceptable alternative to EPA Methods 3B, 29 and 30B.

The EPA is allowing use of the VCS ASTM D6784–16, ''Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)'' as an acceptable alternative to EPA Method 29 (Hg portion only) as a method for measuring Hg concentrations ranging from approximately 0.5 to 100 micrograms per normal cubic meter (µg/Nm^3). This test method describes equipment and procedures for obtaining samples from effluent ducts and stacks, equipment and procedures for laboratory analysis, and procedures for calculating results. VCS ASTM D6784–16 allows for additional flexibility in the sampling and analytical procedures from the earlier version of the same standard VCS ASTM D6784–02 (Reapproved 2008). VCS ASTM D6784–16 allows for the use of either an EPA Method 17 sampling configuration with a fixed (single) point where the flue gas is not stratified, or an EPA Method 5 sampling configuration with a multi-point traverse. For this action, only the EPA Method 5 sampling configuration with a multi-point traverse can be used. This method is available at ASTM International, 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428–2959. See *https://www.astm.org/*. The standard is available to everyone at a cost determined by ASTM ($82). The cost of obtaining this method is not a significant financial burden, making the method reasonably available. Additional detailed information on the VCS search and determination can be found in the memorandum, *Voluntary Consensus Standard Results for National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing,* which is available in the docket for this action. The EPA solicited comment on potentially applicable VCS in the proposal for this rule. However, no other VCS were identified. The EPA is finalizing as proposed incorporating by reference the VCS ASTM D6784–16, ''Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method),'' as an acceptable alternative to EPA Method 29 (Hg portion only).

H. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

The EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with EJ concerns. The assessment of populations in close proximity of taconite iron ore processing plants shows Native American and low-income populations are higher than the national average (see section IV.E of this preamble). The higher percentages of Native American populations are near the UTAC and Minntac facilities. The higher percentages of low-income populations are near the Keetac, Hibbing, Minorca, and Minntac facilities. The EPA believes that this action is likely to reduce existing disproportionate and adverse effects on low-income populations and/or indigenous peoples. The EPA is finalizing new MACT standards for Hg and revised standards for HCl and HF. The EPA expects that at least five facilities would have to implement control measures to reduce Hg emissions to comply with the new Hg MACT standard (including the UTAC, Keetac, Hibbing, Minorca and Minntac facilities) and one facility would need to implement control measures to reduce HCl emissions to comply with the revised standard for HCl (the Tilden facility). HAP exposures for indigenous peoples and low-income individuals living near these six facilities would decrease. The methodology and the results of the demographic analysis are available in the docket for this action in the technical report *Analysis of Demographic Factors For Populations Living Near Taconite Iron Ore Processing Source Category Operations.*

I. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045 (62 FR 19885; April 23, 1997) directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is not subject to Executive Order 13045 because it is not significant as defined in Executive Order 12866(3)(f)(1), and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. In 2020, the EPA conducted a residual risk assessment and determined that risk from the Taconite Iron Ore Processing source category was acceptable, and the standards provided an ample margin of safety to protect public health (see 85 FR 45476 and Docket ID No. EPA–HQ–OAR–2017–0664–0163). For this rulemaking, we updated that risk analysis using new emissions data that the EPA received for some HAP emissions sources at the taconite facilities. We determined that these new HAP emissions estimates would not significantly change our previous estimates of the human health risk posed by the Taconite Iron Ore Processing source category. In this action the EPA is promulgating new emission standards for one previously unregulated pollutant (Hg) and revised emissions standards for two currently regulated pollutants (HCl and HF). These emissions standards will reduce Hg, HCl and HF emissions and thereby reduce children's exposure to these harmful HAP. We estimate that the installation of controls will reduce HCl and HF emissions by 683 tpy and 36 tpy, respectively, and will reduce Hg emissions by up to 247 pounds per year (0.12 tpy).

This action's health and risk assessments are protective of the most vulnerable populations, including children, due to how we determine exposure and through the health benchmarks that we use. Specifically, the risk assessments we perform assume a lifetime of exposure, in which populations are conservatively presumed to be exposed to airborne concentrations at their residence continuously, 24 hours per day for a 70-year lifetime, including childhood. With regards to children's potentially greater susceptibility to noncancer toxicants, the assessments rely on the EPA's (or comparable) hazard identification and dose-response values that have been developed to be protective for all subgroups of the general population, including children. For more information on the risk assessment methods, see the risk report for the July 28, 2020, final Taconite residual risk and technology review (RTR) rule (85 FR 45476), which is available in the docket. Therefore, the rulemaking finalizes actions that will result in health benefits to children by reducing the level of HAP emissions emitted from taconite iron ore processing plants.

J. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. We have concluded that this action is not likely to have any adverse energy effects because it contains no regulatory requirements that will have an adverse impact on productivity, competition, or prices in the energy sector.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 63

Environmental protection, air pollution control, hazardous substances, incorporation by reference, mercury, hydrogen chloride, hydrogen fluoride, reporting and recordkeeping requirements.

Michael S. Regan,
Administrator.

For the reasons stated in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. Section 63.14 is amended by revising paragraph (i)(104) to read as follows:

§ 63.14 Incorporation by reference

* * * * *

(i) * * *

(104) ASTM D6784–16, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), Approved March 1, 2016; IBR approved for §§ 63.9621(d); table 5 to subpart UUUUU; appendix A to subpart UUUUU.

Subpart RRRRR—National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing

■ 3. Section 63.9583 is revised and republished to read as follows:

§ 63.9583 When do I have to comply with this subpart?

(a) If you have an existing affected source, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you no later than October 30, 2006, except as specified in paragraph (f) of this section.

(b) If you have a new affected source and its initial startup date is on or before October 30, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you by October 30, 2003, except as specified in paragraph (f) of this section.

(c) If you have a new affected source and its initial startup date is after October 30, 2003, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you upon initial startup, except as specified in paragraph (f) of this section.

(d) If your taconite iron ore processing plant is an area source that becomes a major source of HAP, the compliance dates in paragraphs (d)(1) and (2) of this section apply to you.

(1) Any portion of the taconite iron ore processing plant that is a new affected source or a new reconstructed source must be in compliance with this subpart upon startup.

(2) All other parts of the taconite iron ore processing plant must be in compliance with this subpart no later than 3 years after the plant becomes a major source.

(e) You must meet the notification and schedule requirements in § 63.9640. Several of these notifications must be submitted before the compliance date for your affected source.

(f) If you have an affected indurating furnace that commenced construction before May 15, 2023, you must comply with the requirements in paragraphs (f)(1) through (7) of this section by March 8, 2027. If you have an affected indurating furnace that commenced construction or reconstruction on or after May 15, 2023, you must comply with the requirements in paragraphs (f)(1) through (7) of this section by March 6, 2024 or the date of initial startup, whichever is later.

(1) All applicable emission limits for mercury, hydrogen chloride, and hydrogen fluoride in tables 2 and 3 to this subpart.

(2) All applicable operating limits in § 63.9590(b)(5) through (8), established in accordance with § 63.9622(g) through (i), for each control device used to comply with the mercury, hydrogen chloride, and hydrogen fluoride emission limits.

(3) All applicable compliance requirements in §§ 63.9600, 63.9610, 63.9623, 63.9625, and 63.9637(a).

(4) The applicable performance testing or continuous emissions monitoring system (CEMS) requirements for mercury in §§ 63.9620(k), 63.9621(d), and 63.9630.

(5) All applicable performance testing requirements in §§ 63.9620(l), 63.9621(d), and 63.9630.

(6) The requirements to install and maintain monitoring equipment in § 63.6332(g) through (i) and the monitoring requirements in §§ 63.9631, 63.9633, and 63.9634 for each control device used to comply with the mercury, hydrogen chloride and hydrogen fluoride emission limits.

(7) The notification, reporting and recordkeeping requirements in §§ 63.9640, 63.9641, 63.9642, and 63.9643 applicable to the mercury, hydrogen chloride, and hydrogen fluoride emission standards.

■ 4. Section 63.9590 is revised and republished to read as follows:

§ 63.9590 What emission limitations and operating limits must I meet?

(a) You must meet each emission limit in tables 1 through 3 to this subpart that applies to you by the applicable compliance date specified in § 63.9583.

(b) You must meet each applicable operating limit for control devices in paragraphs (b)(1) through (8) of this section that applies to you by the applicable compliance date specified in § 63.9583. You are not required to establish and comply with operating limits for control devices used to reduce mercury emissions when you are using a CEMS to monitor and demonstrate compliance with the mercury emission limit in table 2 to this subpart.

(1) Except as provided in paragraph (b)(2) of this section, for each wet scrubber applied to meet any particulate matter emission limit in table 1 to this subpart, you must maintain the daily average pressure drop and daily average scrubber water flow rate at or above the minimum levels established in § 63.9622.

(2) On or before January 28, 2022, for affected sources that commenced construction or reconstruction on or before September 25, 2019, for each dynamic wet scrubber applied to meet any particulate matter emission limit in table 1 to this subpart, you must maintain the daily average scrubber water flow rate and either the daily average fan amperage (a surrogate for fan speed as revolutions per minute) or the daily average pressure drop at or above the minimum levels established during the initial performance test. After January 28, 2022, for affected sources that commenced construction or reconstruction on or before September 25, 2019, and after July 28, 2020, or upon start-up, which ever date is later, for affected sources that commenced construction or reconstruction after September 25, 2019, for each dynamic wet scrubber applied to meet any particulate matter emission limit in table 1 to this subpart, you must maintain the daily average scrubber water flow rate and the daily average fan amperage (a surrogate for fan speed as revolutions per minute) at or above the minimum levels established in § 63.9622.

(3) For each dry electrostatic precipitator (ESP) applied to meet any particulate matter emission limit in Table 1 to this subpart, you must meet the operating limits in paragraph (b)(3)(i) or (ii) of this section.

(i) Maintain the 6-minute average opacity of emissions exiting the control device stack at or below the level established during the initial performance test.

(ii) Maintain the daily average secondary voltage and daily average secondary current for each field at or above the minimum levels established during the initial performance test.

(4) For each wet ESP applied to meet any particulate matter emission limit in table 1 to this subpart, you must meet the operating limits in paragraphs (b)(4)(i) through (iii) of this section.

(i) Maintain the daily average secondary voltage for each field at or above the minimum levels established during the initial performance test.

(ii) Maintain the daily average stack outlet temperature at or below the maximum levels established during the initial performance test.

(iii) Maintain the daily average water flow rate at or above the minimum levels established during the initial performance test.

(5) For each wet scrubber and wet ESP used to meet the hydrogen chloride and hydrogen fluoride emission limits in table 3 to this subpart, you must maintain the daily average scrubber water flow rate and pH greater than or equal to the operating limits established for these parameters established in § 63.9622.

(6) For each activated carbon injection (ACI) system used to meet the mercury emission limit in table 2 to this subpart, you must maintain the daily average activated carbon injection rate greater than or equal to the average activated carbon injection rate established during the most recent performance test demonstrating compliance with the applicable emission limit. In addition, you must maintain the daily average carrier gas flow rate greater than or equal to the average carrier gas flow rate established during the most recent performance test demonstrating compliance with the applicable emission limit.

(7) For each dry sorbent injection (DSI) system used to meet the hydrogen chloride and hydrogen fluoride emission limits in table 3 to this subpart, you must maintain the daily average dry sorbent injection rate greater than or equal to the average dry sorbent injection rate established during the most recent performance test. demonstrating compliance with the applicable emission limit. In addition, you must maintain the daily average carrier gas flow rate greater than or equal to the average carrier gas flow rate established during the most recent performance test demonstrating compliance with the applicable emission limit.

(8) If you use any air pollution control device other than a baghouse, wet scrubber, dynamic scrubber, dry ESP, wet ESP, ACI, or DSI, you must submit a site-specific monitoring plan in accordance with § 63.9631(f).

(c) You may petition the Administrator for approval of alternatives to the monitoring requirements in paragraphs (b)(1) through (7) of this section as allowed under § 63.8(f) and as defined in § 63.90.

■ 5. Section 63.9600 is amended by revising paragraph (b) introductory text to read as follows:

§ 63.9600 What are my operation and maintenance requirements?

* * * * *

(b) You must prepare, and at all times, operate according to, a written operation and maintenance plan for each control device applied to meet any particulate matter emission limit in table 1 to this subpart, mercury emission limit in table 2 to this subpart, hydrogen chloride and hydrogen fluoride emission limit in table 3 to this subpart, and to meet the requirement of each indurating furnace subject to good combustion practices (GCP). Each site-specific operation and maintenance plan must be submitted to the Administrator on or before the compliance date that is specified in § 63.9583 for your affected source. The plan you submit must explain why the chosen practices (*i.e.,* quantified objectives) are effective in performing corrective actions or GCP in minimizing the formation of formaldehyde (and other products of incomplete combustion). The Administrator will review the adequacy of the site-specific practices and objectives you will follow and the records you will keep to demonstrate compliance with your Plan. If the Administrator determines that any portion of your operation and maintenance plan is not adequate, we can reject those portions of the plan, and request that you provide additional information addressing the relevant issues. In the interim of this process, you will continue to follow your current site-specific practices and objectives, as submitted, until your revisions are accepted as adequate by the Administrator. You must maintain a current copy of the operation and maintenance plan onsite, and it must be available for inspection upon request. You must keep the plan for the life of the affected source or until the affected source is no longer subject to the requirements of this subpart. Each operation and maintenance plan must address the elements in paragraphs (b)(1) through (4) of this section.

* * * * *

■ 6. Section 63.9610 is amended by revising paragraph (a) introductory text and adding paragraph (d) to read as follows:

§ 63.9610 What are my general requirements for complying with this subpart?

(a) On or before January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, you must be in compliance with the requirements in paragraphs (a)(1) through (6) of this section at all times, except during periods of startup, shutdown, and malfunction. After January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, and after July 28, 2020, for affected sources that commenced construction or reconstruction after September 25, 2019, you must be in compliance with the emission limitations, standards, and operation and maintenance requirements for the particulate matter emission standards in this subpart at all times.

* * * * *

(d) On and after the applicable compliance date specified in § 63.9583(f), you must be in compliance with all applicable emission limitations for mercury, hydrogen chloride and hydrogen fluoride in tables 2 and 3 to this subpart and with the requirements in paragraphs (d)(1) through (6) of this section at all times.

(1) All applicable operating limits in § 63.9590(b)(5) through (8).

(2) All applicable operation and maintenance requirements in § 63.9600 for control devices and monitoring equipment used to comply with the emissions limits.

(3) The requirements in § 63.9631(j), if you use emissions averaging to demonstrate compliance with the mercury standards.

(4) The requirements in § 63.9631(k), if you use continuous emissions monitoring system(s) (CEMS) to demonstrate compliance with the mercury standards.

(5) The requirements in § 63.9634(n), if you elect to adjust the activated carbon injection rate based on the taconite pellet production rate.

(6) The notification, reporting and recordkeeping requirements in §§ 63.9640 through 63.9643.

■ 7. Section 63.9620 is amended by:

■ a. Revising paragraphs (b)(2) and (f)(2); and

■ b. Adding paragraphs (k) and (l).

The revisions and addition read as follows:

§ 63.9620 On which units and by what date must I conduct performance tests or other initial compliance demonstrations?

* * * * *

(b) * * *

(2) Initial performance tests must be completed no later than 180 calendar days after the compliance date specified in § 63.9583. Performance tests conducted between October 30, 2003, and no later than 180 days after the corresponding compliance date can be used for initial compliance demonstration, provided the tests meet the initial performance testing requirements of this subpart. For an indurating furnace with multiple stacks, the performance tests for all stacks must be completed within 7 calendar days of commencement of the performance tests, to the extent practicable, and the indurating furnace and associated control device (where applicable) operating characteristics must remain representative and consistent for the duration of the stack tests. If you determine that the performance tests cannot be completed within 7 calendar days, the Administrator must be notified within 24 hours of making that determination.

* * * * *

(f) * * *

(2) All emission units within a group must also have the same type of air pollution control device (*e.g.,* wet scrubbers, dynamic wet scrubbers, rotoclones, multiclones, wet and dry ESP, and baghouses). You cannot group emission units with different air pollution control device types together for the purposes of this section.

* * * * *

(k) For each indurating furnace, you must demonstrate initial compliance with the mercury emission limits in table 2 to this subpart in accordance with the procedures specified in either paragraph (k)(1) or (2) of this section.

(1) Complete an initial performance test on all stacks associated with each indurating furnace no later than 180 calendar days after the compliance date specified in § 63.9583(f). Performance tests conducted between March 6, 2024 and 180 days after the corresponding compliance date can be used for initial compliance demonstration, provided the tests meet the initial performance testing requirements of this subpart. For an indurating furnace with multiple stacks, the performance tests for all stacks must be completed within 7 calendar days of commencement of the performance tests, to the extent practicable, and the indurating furnace and associated control device (where applicable) operating characteristics must remain representative and consistent for the duration of the stack tests. If you determine that the performance tests cannot be completed within 7 calendar days, the Administrator must be notified within 24 hours of making that determination.

(2) You may use a 30-day rolling average of the 1-hour arithmetic average CEMS data. You must conduct a performance evaluation of each CEMS within 180 days of installation of the monitoring system. The initial performance evaluation must be conducted prior to collecting CEMS data

that will be used for the initial compliance demonstration.

(l) For each indurating furnace, you must demonstrate initial compliance with the emission limits in table 3 to this subpart by conducting initial performance tests for hydrogen chloride and hydrogen fluoride on all stacks associated with each indurating furnace. Initial performance tests must be completed no later than 180 calendar days after the compliance date specified in § 63.9583(f). Performance tests conducted between March 6, 2024 and 180 days after the corresponding compliance date can be used for initial compliance demonstration, provided the tests meet the initial performance testing requirements of this subpart. For an indurating furnace with multiple stacks, the performance tests for all stacks must be completed within 7 calendar days of commencement of the performance tests, to the extent practicable, and the indurating furnace and associated control device (where applicable) operating characteristics must remain representative and consistent for the duration of the stack tests. If you determine that the performance tests cannot be conducted within 7 calendar days, the Administrator must be notified within 24 hours of making that determination.

■ 8. Section 63.9621 is amended by:
■ a. Revising the section heading;
■ b. Revising paragraphs (a) and (c) introductory text; and
■ c. Adding paragraphs (d) and (e).

The revisions and additions read as follows:

§ 63.9621 What test methods and other procedures must I use to demonstrate initial compliance with the emission limits?

(a) On or before January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, you must conduct each performance test that applies to your affected source according to the requirements in § 63.7(e)(1) and paragraphs (b) and (c) of this section. After January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, and after July 28, 2020, or upon start-up, which ever date is later, for affected sources that commenced construction or reconstruction after September 25, 2019, you must conduct each performance test that applies to your affected source, including the initial performance tests for mercury required in § 63.9620(k)(1) and the initial performance tests for hydrogen chloride and hydrogen fluoride required in § 63.9620(l), under normal operating conditions of the affected source. The owner or 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 such conditions represent normal operation. 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. You must also conduct each performance test that applies to your affected source according to the requirements in paragraphs (b) and (c) of this section.

* * * * *

(c) For each ore dryer affected source and each indurating furnace affected source, you must determine compliance with the applicable emission limit for particulate matter in table 1 to this subpart by following the test methods and procedures in paragraphs (c)(1) through (2) of this section.

* * * * *

(d) For each indurating furnace subject to the initial performance testing under § 63.9620(k)(1) or (l), you must determine compliance with the applicable emission limits for mercury, hydrogen chloride and hydrogen fluoride in tables 2 and 3 to this subpart by following the test methods and procedures in paragraphs (d)(1) through (9) of this section. You are not required to complete the initial performance test for mercury emissions when you are using a CEMS in accordance with paragraph (e) of this section.

(1) The furnace must be operated at or above 90 percent of capacity throughout the duration of the performance testing. If testing cannot be performed at or above 90 percent of capacity, you must provide an explanation for the lower production rate in your performance test plan. The lower production rate must be approved by the Administrator prior to beginning performance testing. For indurating furnaces that comply with the mercury emissions limit in table 2 to this subpart by adjusting the activated carbon injection rate based on the taconite pellet production rate, you must complete the performance testing for mercury in accordance with the provisions in § 63.9634(n).

(2) Use the methods specified in paragraphs (c)(1)(i) through (iv) of this section to select sampling port locations and the number of traverse points and to determine the volumetric flow rate, dry molecular weight, and moisture content of the stack gas.

(3) Determine the concentration of mercury for each stack using Method 29 or Method 30B in 40 CFR part 60, appendix A, or the voluntary consensus standard ASTM D6784–16 (incorporated by reference, see § 63.14). For Method 29 and ASTM D6784–16, the sample volume must be at least 1.7 dry standard cubic meters (dscm) (60 dry standard cubic feet) per run. For Method 30B, each test run must be at least one hour in duration.

(4) Determine the concentration of hydrogen chloride and hydrogen fluoride for each stack using Method 26A in 40 CFR part 60, appendix A. Each test must consist of three separate runs. The minimum sample volume must be at least 2 dscm per run.

(5) During each stack test run, determine the weight of taconite pellets produced and calculate the emissions rate of each pollutant in pounds of pollutant per long ton (lb/LT) of pellets produced for each test run. The weight of taconite pellets produced must be determined by measurement using weigh hoppers, belt weigh feeders, or weighed quantities in shipments, or calculated using the bulk density and volume measurements. If any measurement result for any pollutant is reported as below the method detection limit, use the method detection limit as the measured emissions level for that pollutant when calculating the emission rate. If the furnace has more than one stack, calculate the total emissions rate for each test run by summing the emissions across all stacks, as shown in Equation 4.

$$E_{f,i} = \sum_{s=1}^{n} \frac{C_s \times Q_s}{P_f} \quad (Eq. 4)$$

Where:

$E_{f,i}$ = Emissions rate for test run “i” for all emission stacks on indurating furnace “f”, lb/LT of pellets produced,
C_s = Emission rate for stack “s” measured during test run “i” on indurating furnace “f”, lb/dscf,
Q_s = Average volumetric flow rate of stack gas measured at stack “s” during test run “i” on indurating furnace “f”, dscf/hour;
P_f = Pellets produced in indurating furnace “f” during the stack test, LT; and
n = Number of emissions stacks on furnace “f”.

(6) Calculate the average emissions rate for each furnace using the three test runs, as show in Equation 5 of this section.

$$E_f = \frac{E_1 + E_2 + E_3}{3} \quad (Eq. 5)$$

Where:

E_f = Average emission rate for indurating furnace ''f'', lb/LT of pellets produced,
E_1 = Emissions rate for run 1 for indurating furnace ''f'', lb/LT of pellets produced,
E_2 = Emissions rate for run 2 for indurating furnace ''f'', lb/LT of pellets produced, and
E_3 = Emissions rate for run 3 for indurating furnace ''f'', lb/LT of pellets produced.

(7) For each indurating furnace constructed or reconstructed on or after May 15, 2023, determine compliance with the applicable mercury emission limit in table 2 to this subpart by calculating the average emissions rate from the three test runs performed on the furnace using Equations 4 and 5 of this section.

(8) For each indurating furnace constructed or reconstructed before May 15, 2023, you must determine compliance with the applicable mercury emission limit in accordance with the procedures specified in either paragraph (d)(8)(i) or (ii) of this section.

(i) Determine compliance with the mercury limit for individual furnaces in table 2 to this subpart by calculating the average mercury emissions rate for each affected indurating furnace using Equations 4 and 5 of this section, or

(ii) Determine compliance with the mercury limit for groups of indurating furnaces in table 2 to this subpart in accordance with the method in § 63.9623(d).

(9) Determine compliance with the applicable hydrogen chloride and hydrogen fluoride emission limits in table 3 to this subpart by calculating the average emissions rate for each indurating furnace for the three test runs performed on the furnace using Equations 4 and 5 of this section.

(e) For each indurating furnace using mercury CEMS to demonstrate compliance with the applicable emission limits for mercury, you must determine compliance with the applicable mercury limit in table 2 to this subpart by using a 30-day rolling average of the 1-hour arithmetic average CEMS data, including CEMS data during startup and shutdown as defined in this subpart. The mercury CEMS must be installed, calibrated, maintained, and operated as accordance with the requirements in § 63.9631(j).

■ 9. Section 63.9622 is revised and republished to read as follows:

§ 63.9622 What test methods and other procedures must I use to establish and demonstrate initial compliance with the operating limits?

(a) For wet scrubbers subject to performance testing in § 63.9620 and operating limits for pressure drop and scrubber water flow rate in § 63.9590(b)(1), you must establish site-specific operating limits according to the procedures in paragraphs (a)(1) through (3) of this section.

(1) Using the CPMS required in § 63.9631(b), measure and record the pressure drop and scrubber water flow rate every 15 minutes during each run of the particulate matter performance test.

(2) Calculate and record the average pressure drop and scrubber water flow rate for each individual test run. Your operating limits are established as the lowest average pressure drop and the lowest average scrubber water flow rate corresponding to any of the three test runs, except as specified in paragraph (g)(2) of this section.

(3) If a rod-deck venturi scrubber is applied to an indurating furnace to meet any particulate matter emission limit in table 1 to this subpart, you may establish a lower average pressure drop operating limit by using historical average pressure drop data from a certified performance test completed on or after December 18, 2002 instead of using the average pressure drop value determined during the initial performance test, as specified in paragraph (a)(2) of this section. If historical average pressure drop data are used to establish an operating limit (*i.e.,* using data from a certified performance test conducted prior to the promulgation date of the final rule), then the average particulate matter concentration corresponding to the historical performance test must be at or below the applicable indurating furnace emission limit, as listed in table 1 to this subpart.

(b) On or before January 28, 2022, for affected sources that commenced construction or reconstruction on or before September 25, 2019, for dynamic wet scrubbers subject to performance testing in § 63.9620 and operating limits for scrubber water flow rate and either fan amperage or pressure drop in § 63.9590(b)(2), you must establish site-specific operating limits according to the procedures in paragraphs (b)(1) and (2) of this section. After January 28, 2022, for affected sources that commenced construction or reconstruction on or before September 25, 2019, and after July 28, 2020, or upon start-up, which ever date is later, for affected sources that commenced construction or reconstruction after September 25, 2019, for dynamic wet scrubbers subject to performance testing in § 63.9620 and operating limits for scrubber water flow rate and fan amperage in § 63.9590(b)(2), you must establish site-specific operating limits according to the procedures in paragraphs (b)(1) and (2) of this section.

(1) On or before January 28, 2022, for affected sources that commenced construction or reconstruction on or before September 25, 2019, using the CPMS required in § 63.9631(b), measure and record the scrubber water flow rate and either the fan amperage or pressure drop every 15 minutes during each run of the particulate matter performance test. After January 28, 2022, for affected sources that commenced construction or reconstruction on or before September 25, 2019, and after July 28, 2020, or upon start-up, which ever date is later, for affected sources that commenced construction or reconstruction after September 25, 2019, using the CPMS required in § 63.9631(b), measure and record the scrubber water flow rate and the fan amperage every 15 minutes during each run of the particulate matter performance test.

(2) On or before January 28, 2022, for affected sources that commenced construction or reconstruction on or before September 25, 2019, calculate and record the average scrubber water flow rate and either the average fan amperage or the average pressure drop for each individual test run. Your operating limits are established as the lowest average scrubber water flow rate and either the lowest average fan amperage or pressure drop value corresponding to any of the three test runs. After January 28, 2022, for affected sources that commenced construction or reconstruction on or before September 25, 2019, and after July 28, 2020, or upon start-up, which ever date is later, for affected sources that commenced construction or reconstruction after September 25, 2019, calculate and record the average scrubber water flow rate and the average fan amperage for each individual test run. Your operating limits are established as the lowest average scrubber water flow rate and the lowest average fan amperage value corresponding to any of the three test runs, except as specified in paragraph (g)(2) of this section.

(c) For a dry ESP subject to performance testing in § 63.9620 and operating limits in § 63.9590(b)(3), you must establish a site-specific operating limit according to the procedures in paragraphs (c)(1) or (2) of this section.

(1) If the operating limit for your dry ESP is a 6-minute average opacity of emissions value, then you must follow the requirements in paragraphs (c)(1)(i) through (iii) of this section.

(i) Using the continuous opacity monitoring system (COMS) required in § 63.9631(d)(1), measure and record the opacity of emissions from each control device stack during the particulate matter performance test.

(ii) Compute and record the 6-minute opacity averages from 24 or more data points equally spaced over each 6-minute period (*e.g.,* at 15-second intervals) during the test runs.

(iii) Using the opacity measurements from a performance test that meets the emission limit, determine the opacity value corresponding to the 99 percent upper confidence level of a normal distribution of the 6-minute opacity averages.

(2) If the operating limit for your dry ESP is the daily average secondary voltage and daily average secondary current for each field, then you must follow the requirements in paragraphs (c)(2)(i) and (ii) of this section.

(i) Using the CPMS required in § 63.9631(d)(2), measure and record the secondary voltage and secondary current for each dry ESP field every 15 minutes during each run of the particulate matter performance test.

(ii) Calculate and record the average secondary voltage and secondary current for each dry ESP field for each individual test run. Your operating limits are established as the lowest average secondary voltage and secondary current value for each dry ESP field corresponding to any of the three test runs.

(d) For a wet ESP subject to performance testing in § 63.9620 and operating limit in § 63.9590(b)(4), you must establish a site-specific operating limit according to the procedures in paragraphs (d)(1) and (2) of this section.

(1) Using the CPMS required in § 63.9631(e), measure and record the parametric values in paragraphs (d)(1)(i) through (iii) of this section for each wet ESP field every 15 minutes during each run of the particulate matter performance test.

(i) Secondary voltage;

(ii) Water flow rate; and

(iii) Stack outlet temperature.

(2) For each individual test run, calculate and record the average value for each operating parameter in paragraphs (d)(1)(i) through (iii) of this section for each wet ESP field. Your operating limits are established as the lowest average value for each operating parameter of secondary voltage and water flow rate corresponding to any of the three test runs, and the highest average value for each stack outlet temperature corresponding to any of the three test runs.

(e) If you use an air pollution control device other than a wet scrubber, dynamic wet scrubber, dry ESP, wet ESP, or baghouse, and it is subject to performance testing in § 63.9620, you must submit a site-specific monitoring plan in accordance with § 63.9631(f). The site-specific monitoring plan must include the site-specific procedures for demonstrating initial and continuous compliance with the corresponding operating limits.

(f) You may change the operating limits for any air pollution control device as long as you meet the requirements in paragraphs (f)(1) through (3) of this section.

(1) Submit a written notification to the Administrator of your request to conduct a new performance test to revise the operating limit.

(2) Conduct a performance test to demonstrate compliance with the applicable emission limitation in table 1 to this subpart.

(3) Establish revised operating limits according to the applicable procedures in paragraphs (a) through (e) of this section.

(g) For wet scrubbers and wet ESPs subject to performance testing in § 63.9620(l) and operating limits for scrubber water flow rate and pH in § 63.9590(b)(5), you must establish site-specific operating limits according to the procedures in paragraphs (g)(1) and (2) of this section.

(1) Using the CPMS required in § 63.9631(b), measure and record the scrubber water flow rate and pH of the scrubber water effluent every 15 minutes during each run of the performance test for hydrogen chloride and hydrogen fluoride.

(2) Calculate and record the average scrubber water flow rate and average pH of the scrubber water effluent for each individual test run. Your operating limit must be established as the average scrubber water flow rate and average pH of the scrubber water of the three test runs. If a higher average flow rate is measured during the most recent PM performance test, the operating limit for the daily average scrubber water flow rate is the average scrubber water flow rate measured during the most recent PM performance test. If a higher average flow rate is measured during the most recent HCl and HF performance test, the operating limit for the daily average scrubber water flow rate is the average scrubber water flow rate measured during the most recent HCl and HF performance test.

(h) For ACI systems subject to performance testing in § 63.9620(k)(1) and operating limits for activated carbon sorbent injection rate and carrier gas flow rate in § 63.9590(b)(6), you must establish site-specific operating limits according to the procedures in paragraphs (h)(1) and (2) of this section.

(1) Using the CPMS required in § 63.9631(b), measure and record the activated carbon injection rate and carrier gas flow rate every 15 minutes during each run of the performance test for mercury.

(2) Calculate and record the average activated carbon injection rate and carrier gas flow rate for each individual test run. Your operating limit must be established as the highest activated carbon injection rate and carrier gas flow rate of the three test runs.

(i) For DSI systems subject to performance testing in § 63.9620(l) and operating limits for sorbent injection rate and carrier gas flow rate in § 63.9590(b)(7), you must establish site-specific operating limits according to the procedures in paragraphs (i)(1) and (2) of this section.

(1) Using the CPMS required in § 63.9631(b), measure and record the sorbent injection rate and carrier gas flow rate every 15 minutes during each run of the performance test for hydrogen chloride and hydrogen fluoride.

(2) Calculate and record the average sorbent injection rate and carrier gas flow rate for each individual test run. Your operating limit must be established as the highest average sorbent injection rate and carrier gas flow rate of the three test runs.

■ 10. Section 63.9623 is revised and republished to read as follows:

§ 63.9623 How do I demonstrate initial compliance with the emission limitations that apply to me?

(a) For each affected source subject to an emission limit in tables 1 through 3 to this subpart, you must demonstrate initial compliance by meeting the emission limit requirements in paragraphs (a)(1) through (8) of this section by the compliance date specified in § 63.9583.

(1) For ore crushing and handling, the flow-weighted mean concentration of particulate matter, determined according to the procedures in §§ 63.9620(a) and 63.9621(b), must not exceed the emission limits in table 1 to this subpart.

(2) For indurating furnaces, the flow-weighted mean concentration of particulate matter, determined according to the procedures in §§ 63.9620(b) and 63.9621(c), must not exceed the emission limits in table 1 to this subpart.

(3) For finished pellet handling, the flow-weighted mean concentration of particulate matter, determined according to the procedures in §§ 63.9620(c) and 63.9621(b), must not exceed the emission limits in table 1 to this subpart.

(4) For ore dryers, the flow-weighted mean concentration of particulate matter, determined according to the

procedures in §§ 63.9620(d) and 63.9621(c), must not exceed the emission limits in table 1 to this subpart.

(5) For indurating furnaces not using emissions averaging, the mercury emissions determined according to the procedures in §§ 63.9620(k)(1) or (2) and 63.9621(d), must not exceed the applicable emission limit in table 2 to this subpart.

(6) For indurating furnaces that comply with the mercury emissions limit using emissions averaging, the average mercury emissions determined according to the procedures in §§ 63.9620(k)(1) or (2), 63.9621(d) and 63.9634(m), must not exceed the applicable emission limit in table 2 to this subpart.

(7) For indurating furnaces that comply with the mercury emissions limit by adjusting the activated carbon injection rate based on the taconite pellet production rate, the mercury emissions determined according to the procedures in §§ 63.9620(k)(1) or (2), 63.9621(d) or (e), and 63.9634(n), must not exceed the applicable emission limit in table 2 to this subpart.

(8) For indurating furnaces, the hydrogen chloride and hydrogen fluoride emissions determined according to the procedures in §§ 63.9620(l) and 63.9621(d), must not exceed the applicable emission limit in table 3 to this subpart.

(b) For each affected source subject to an emission limit in table 1 to this subpart, you must demonstrate initial compliance by meeting the operating limit requirements in paragraphs (b)(1) through (5) of this section.

(1) For each wet scrubber subject to performance testing in § 63.9620 and operating limits for pressure drop and scrubber water flow rate in § 63.9590(b)(1), you have established appropriate site-specific operating limits and have a record of the pressure drop and scrubber water flow rate measured during the performance test in accordance with § 63.9622(a).

(2) On or before January 28, 2022, for affected sources that commenced construction or reconstruction on or before September 25, 2019, for each dynamic wet scrubber subject to performance testing in § 63.9620 and operating limits for scrubber water flow rate and either fan amperage or pressure drop in § 63.9590(b)(2), you have established appropriate site-specific operating limits and have a record of the scrubber water flow rate and either the fan amperage or pressure drop value, measured during the performance test in accordance with § 63.9622(b). After January 28, 2022, for affected sources that commenced construction or reconstruction on or before September 25, 2019, and after July 28, 2020, or upon start-up, which ever date is later, for affected sources that commenced construction or reconstruction after September 25, 2019, for each dynamic wet scrubber subject to performance testing in § 63.9620 and operating limits for scrubber water flow rate and fan amperage in § 63.9590(b)(2), you have established appropriate site-specific operating limits and have a record of the scrubber water flow rate and the fan amperage value, measured during the performance test in accordance with § 63.9622(b).

(3) For each dry ESP subject to performance testing in § 63.9620 and one of the operating limits in § 63.9590(b)(3), you must meet the requirements in paragraph (b)(3)(i) or (ii) of this section.

(i) If you are subject to the operating limit for opacity in § 63.9590(b)(3)(i), you have established appropriate site-specific operating limits and have a record of the opacity measured during the performance test in accordance with § 63.9622(c)(1).

(ii) If you are subject to the operating limit for secondary voltage and secondary current in § 63.9590(b)(3)(ii), you have established appropriate site-specific operating limits and have a record of the secondary voltage and secondary current measured during the performance test in accordance with § 63.9622(c)(2).

(4) For each wet ESP subject to performance testing in § 63.9620 and operating limits for secondary voltage, water flow rate, and stack outlet temperature in § 63.9590(b)(4), you have established appropriate site-specific operating limits and have a record of the secondary voltage, water flow rate, and stack outlet temperature measured during the performance test in accordance with § 63.9622(d).

(5) For other air pollution control devices subject to performance testing in § 63.9620 and operating limits in accordance with § 63.9590(b)(8), you have submitted a site-specific monitoring plan in accordance with § 63.9631(f) and have a record of the site-specific operating limits as measured during the performance test in accordance with § 63.9622(e).

(c) Except as specified in paragraph (e) of this section, you must demonstrate initial compliance with the emission limits in tables 2 and 3 to this subpart, by meeting the operating limit requirements in paragraphs (c)(1) through (3) of this section.

(1) For each wet scrubber and wet ESP subject to performance testing in § 63.9620(k) and operating limits for scrubber water flow rate and pH in § 63.9590(b)(5), you have established appropriate site-specific operating limits and have a record of the scrubber water flow rate and pH measured during the performance test in accordance with § 63.9622(g).

(2) For each ACI subject to performance testing in § 63.9620(k) and operating limits for activated carbon injection rate and carrier gas flow rate in § 63.9590(b)(6), you have established appropriate site-specific operating limits and have a record of the activated carbon injection rate and carrier gas flow rate measured during the performance test in accordance with § 63.9622(i).(3) For each DSI subject to performance testing in § 63.9620(k) and operating limits for sorbent injection rate and carrier gas flow rate in § 63.9590(b)(7), you have established appropriate site-specific operating limit and have a record of the sorbent injection rate and carrier gas flow rate measured during the performance test in accordance with § 63.9622(h).

(d) If you elect to comply with the mercury limit in table 2 to this subpart using emissions averaging for indurating furnaces constructed or reconstructed before May 15, 2023, you must comply with the requirements in paragraphs (d)(1) through (4) of this section.

(1) Before submitting the implementation plan required in paragraph (d)(3) of this section, you must complete the mercury stack testing required in § 63.9620(k)(1) or install, calibrate, and operate a mercury CEMS pursuant to § 63.9620(k)(2) and paragraph (e) of this section for all indurating furnaces you wish to include in the mercury emission average.

(2) You must develop and submit to the applicable regulatory authority for review and approval, an implementation plan for mercury emission averaging no later than 180 days before the date you intend to demonstrate compliance using the emission averaging option. You must include the information contained in paragraphs (d)(2)(i) through (iii) of this section in your implementation plan.

(i) Identification of all indurating furnaces in the averaging group, including the typical taconite pellet production rate, control technology installed, and types of fuel(s) that will be burned.

(ii) The mercury emission rate for each furnace for each of the fuels identified in paragraph (d)(2)(i) of this section.

(iii) The date on which you are requesting emission averaging to commence.

(3) The regulatory authority shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all the information specified in paragraph (d)(2) of this section, and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable regulatory authority shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Averaging that includes indurating furnaces constructed or reconstructed on or after May 15, 2023, or

(ii) Averaging between indurating furnaces located at different facilities.

(e) If you elect to demonstrate compliance with the mercury limit in table 2 to this subpart using a mercury CEMS, you must calculate the 30-day rolling average of 1-hour arithmetic average emission concentrations, including CEMS data during startup and shutdown, calculated using equation 19–19 in section 12.4.1 of EPA Reference Method 19 at appendix A–7 of 40 CFR part 60. The 1-hour arithmetic averages for CEMS must be calculated using the data points required under § 63.8(c)(4)(ii).

(f) For each emission limitation and operating limit that applies to you, you must submit a notification of compliance status according to § 63.9640(e)

■ 11. Section 63.9630 is amended by revising paragraphs (b) and (e)(2) to read as follows:

§ 63.9630 When must I conduct subsequent performance tests?

* * * * *

(b) You must conduct subsequent performance tests on all stacks associated with indurating furnaces to demonstrate continued compliance with the indurating furnace emission limits in tables 1 through 3 to this subpart according to the schedule developed by your permitting authority and shown in your title V permit, but no less frequent than twice per 5-year permit term. If a title V permit has not been issued, you must submit a testing plan and schedule, containing the information specified in paragraph (e) of this section, to the permitting authority for approval. For an indurating furnace with multiple stacks, the performance tests for all stacks must be conducted within 7 calendar days of commencement of the performance tests, to the extent practicable, and the indurating furnace and associated control device (where applicable) operating characteristics must remain representative and consistent for the duration of the stack tests. If you determine that the performance tests cannot be completed within 7 calendar days, the Administrator must be notified within 24 hours of making that determination. Performance testing for mercury is not required for furnaces using CEMS to demonstrate compliance with the mercury emission limits in table 2 to this subpart.

* * * * *

(e) * * *

(2) A schedule indicating when you will conduct subsequent performance tests for particulate matter, mercury, hydrogen chloride and hydrogen fluoride for each of the emission units.

■ 12. Section 63.9631 is amended by:

■ a. Revising and republishing paragraphs (d) through (f); and

■ b. Adding paragraphs (g) through (k).

The revisions and additions read as follows:

§ 63.9631 What are my monitoring requirements?

* * * * *

(d) For each dry ESP subject to the operating limits in § 63.9590(b)(3), you must follow the monitoring requirements in paragraph (d)(1) or (2) of this section.

(1) If the operating limit you choose to monitor is the 6-minute average opacity of emissions in accordance with § 63.9590(b)(3)(i), you must install, operate, and maintain a COMS according to the requirements in § 63.9632(f) and monitor the 6-minute average opacity of emissions exiting each control device stack according to the requirements in § 63.9633.

(2) If the operating limit you choose to monitor is average secondary voltage and average secondary current for each dry ESP field in accordance with § 63.9590(b)(3)(ii), you must install, operate, and maintain a CPMS according to the requirements in § 63.9632(b) through (e) and monitor the daily average secondary voltage and daily average secondary current according to the requirements in § 63.9633.

(e) For each wet ESP subject to the operating limits in § 63.9590(b)(4), you must install, operate, and maintain a CPMS according to the requirements in § 63.9632(b) through (e) and monitor the daily average secondary voltage, daily average stack outlet temperature, and daily average water flow rate according to the requirements in § 63.9633.

(f) For each wet scrubber and wet ESP subject to the operating limits in § 63.9590(b)(5), you must install, operate, and maintain a CPMS according to the requirements in § 63.9632(g) and monitor the daily average scrubber water flow rate and pH of the scrubber water effluent.

(g) For each ACI system subject to the operating limits in § 63.9590(b)(6), you must install, operate, and maintain a CPMS according to the requirements in § 63.9632(h) and (i) and monitor the daily average activated carbon injection rate and carrier gas flow rate.

(h) For each DSI system subject to the operating limits in § 63.9590(b)(7), you must install, operate, and maintain a CPMS according to the requirements in § 63.9632(h) and (i) and monitor the daily average sorbent injection rate and carrier gas flow rate.

(i) If you use any air pollution control device other than a baghouse, wet scrubber, dry ESP, wet ESP, DSI, or ACI, you must submit a site-specific monitoring plan that includes the information in paragraphs (i)(1) through (4) of this section. The monitoring plan is subject to approval by the Administrator. You must maintain a current copy of the monitoring plan onsite, and it must be available for inspection upon request. You must keep the plan for the life of the affected source or until the affected source is no longer subject to the requirements of this subpart.

(1) A description of the device.

(2) Test results collected in accordance with § 63.9621 verifying the performance of the device for reducing emissions of particulate matter, mercury, hydrogen chloride, and hydrogen fluoride to the atmosphere to the levels required by this subpart.

(3) A copy of the operation and maintenance plan required in § 63.9600(b).

(4) Appropriate operating parameters that will be monitored to maintain continuous compliance with the applicable emission limitation(s).

(j) If you elect to comply with the mercury limit in table 2 to this subpart using emissions averaging in accordance with an implementation plan approved under the provisions in § 63.9623(d) or you elect to adjust the activated carbon injection rate based on the taconite pellet production rate in accordance with the procedures in § 63.9634(n), you must determine and record the mass of taconite pellets produced each month by each furnace included in the emissions averaging group. The weight of taconite pellets produced must be determined by measurement using weigh hoppers, belt weigh feeders, or weighed quantities in shipments, or calculated using the bulk density and volume measurements.

(k) If you elect to demonstrate compliance with the mercury emissions limits in table 2 to this subpart using a CEMS to measure mercury emissions, you must comply with the requirements in (k)(1) through (5).

(1) Notify the Administrator one month before starting use of the CEMS and notify the Administrator 180-days before ceasing use of the CEMS.

(2) Each CEMS must be installed, certified, calibrated, and maintained 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.

(3) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(4) You must complete the initial performance evaluation of the CEMS within 180 days after notifying the Administrator and before starting to use the CEMS data in lieu of performance testing and monitoring operating parameters to demonstrate compliance.

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. The one-hour arithmetic averages, expressed in units of lb/LT, must be used to calculate 30-day rolling average emissions to determine compliance with the applicable emission limit in table 2 to this subpart.

■ 13. Section 63.9632 is amended by:

■ a. Revising paragraphs (f) introductory text and (f)(2); and

■ b. Adding paragraphs (g) through (i).

The revisions and additions read as follows:

§ 63.9632 What are the installation, operation, and maintenance requirements for my monitoring equipment?

* * * * *

(f) For each dry ESP subject to the opacity operating limit in § 63.9590(b)(3)(i), you must install, operate, and maintain each COMS according to the requirements in paragraphs (f)(1) through (4) of this section.

* * * * *

(2) On or before January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, you must develop and implement a quality control program for operating and maintaining each COMS according to § 63.8. At a minimum, the quality control program must include a daily calibration drift assessment, quarterly performance audit, and annual zero alignment of each COMS. After January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, and after July 28, 2020, or upon start-up, which ever date is later, for affected sources that commenced construction or reconstruction after September 25, 2019, you must develop and implement a quality control program for operating and maintaining each COMS according to § 63.8(a) and (b), (c)(1)(ii), (c)(2) through (8), (d)(1) and (2), and (e) through (g) and Procedure 3 in appendix F to 40 CFR part 60. At a minimum, the quality control program must include a daily calibration drift assessment, quarterly performance audit, and annual zero alignment of each COMS.

* * * * *

(g) For each pH measurement device, in addition to the requirements in paragraphs (b) through (e) of this section, you must meet the requirements in paragraphs (g)(1) through (4) of this section.

(1) The minimum accuracy of the pH measurement device must be ±0.2 pH units.

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

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

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

(h) For each mass flow rate monitor used for measuring the sorbent or activated carbon injection rate, in addition to the requirements in paragraphs (b) through (e) of this section, you must meet the requirements of (h)(1) through (4) of this section.

(1) The minimum accuracy of the mass flow rate monitor must be ±5 percent over the normal range of flow measured.

(2) Locate the device in a position(s) that provides a representative measurement of the total sorbent injection rate.

(3) Install and calibrate the device in accordance with manufacturer's procedures and specifications.

(4) At least annually, conduct a performance evaluation of the injection rate monitoring system in accordance with your monitoring plan.

(i) For each carrier gas flow rate monitor, in addition to the requirements in paragraphs (b) through (e) of this section, you must meet the requirements of (i)(1) through (4) of this section.

(1) The minimum accuracy of the gas flow rate monitor must be ±5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute), whichever is greater.

(2) Locate the device in a position(s) that provides a representative measurement of the carrier gas flow rate.

(3) Install and calibrate the device in accordance with manufacturer's procedures and specifications.

(4) At least annually, conduct a performance evaluation of the carrier gas flow rate monitoring system in accordance with your monitoring plan.

■ 14. Section 63.9634 is amended by revising paragraphs (a), (e)(4), (f)(4), (g) through (j) and adding paragraphs (k) through (n) to read as follows:

§ 63.9634 How do I demonstrate continuous compliance with the emission limitations that apply to me?

(a) For each affected source subject to an emission limit in table 1 to this subpart, you must demonstrate continuous compliance by meeting the requirements in paragraphs (b) through (h) of this section.

* * * * *

(e) * * *

(4) If the daily average pressure drop or daily average scrubber water flow rate is below the operating limits established for a corresponding emission unit or group of similar emission units, you must then follow the corrective action procedures in paragraph (l) of this section.

(f) * * *

(4) On or before January 28, 2022, for affected sources that commenced construction or reconstruction on or before September 25, 2019, if the daily average scrubber water flow rate, daily average fan amperage, or daily average pressure drop is below the operating limits established for a corresponding emission unit or group of similar emission units, you must then follow the corrective action procedures in paragraph (l) of this section. After January 28, 2022, for affected sources that commenced construction or reconstruction on or before September 25, 2019, and after July 28, 2020, or upon start-up, which ever date is later, for affected sources that commenced construction or reconstruction after September 25, 2019, if the daily average scrubber water flow rate or daily average fan amperage, is below the operating limits established for a corresponding emission unit or group of similar emission units, you must then follow the corrective action procedures in paragraph (l) of this section.

(g) For each dry ESP subject to operating limits in § 63.9590(b)(3), you must demonstrate continuous compliance by completing the requirements of paragraph (g)(1) or (2) of this section.

(1) If the operating limit for your dry ESP is a 6-minute average opacity of emissions value, then you must follow the requirements in paragraphs (g)(1)(i) through (iii) of this section.

(i) Maintaining the 6-minute average opacity of emissions at or below the maximum level established during the initial or subsequent performance test.

(ii) Operating and maintaining each COMS and reducing the COMS data according to § 63.9632(f).

(iii) If the 6-minute average opacity of emissions is above the operating limits established for a corresponding emission unit, you must then follow the corrective action procedures in paragraph (l) of this section.

(2) If the operating limit for your dry ESP is the daily average secondary voltage and daily average secondary current for each field, then you must follow the requirements in paragraphs (g)(2)(i) through (iv) of this section.

(i) Maintaining the daily average secondary voltage or daily average secondary current for each field at or above the minimum levels established during the initial or subsequent performance test.

(ii) Operating and maintaining each dry ESP CPMS according to § 63.9632(b) and recording all information needed to document conformance with these requirements.

(iii) Collecting and reducing monitoring data for secondary voltage or secondary current for each field according to § 63.9632(c) and recording all information needed to document conformance with these requirements.

(iv) If the daily average secondary voltage or daily average secondary current for each field is below the operating limits established for a corresponding emission unit, you must then follow the corrective action procedures in paragraph (l) of this section.

(h) For each wet ESP subject to the operating limits for secondary voltage, stack outlet temperature, and water flow rate in § 63.9590(b)(4), you must demonstrate continuous compliance by completing the requirements of paragraphs (h)(1) through (4) of this section.

(1) Maintaining the daily average secondary voltage and daily average scrubber water flow rate for each field at or above the minimum levels established during the initial or subsequent performance test. Maintaining the daily average stack outlet temperature at or below the maximum levels established during the initial or subsequent performance test.

(2) Operating and maintaining each wet ESP CPMS according to § 63.9632(b) and recording all information needed to document conformance with these requirements.

(3) Collecting and reducing monitoring data for secondary voltage, stack outlet temperature, and water flow rate according to § 63.9632(c) and recording all information needed to document conformance with these requirements.

(4) If the daily average secondary voltage, stack outlet temperature, or water flow rate does not meet the operating limits established for a corresponding emission unit, you must then follow the corrective action procedures in paragraph (l) of this section.

(i) For each affected indurating furnace subject to a hydrogen chloride and hydrogen fluoride emission limit in table 3 to this subpart, you must demonstrate continuous compliance by meeting the requirements in paragraphs (i)(1) and (2) of this section.

(1) For each wet scrubber and wet ESP subject to the operating limits for scrubber water flow rate and pH in § 63.9590(b)(5), you must demonstrate continuous compliance by completing the requirements of paragraphs (i)(1)(i) through (iv) of this section.

(i) Maintaining the daily average scrubber water flow rate and daily average pH of the scrubber water effluent at or above the minimum level established during the most recent performance test. If a higher average flow rate is measured during the last PM performance test, the operating limit for daily average scrubber water flow rate is the highest average scrubber water flow rate measured during the last PM performance test.

(ii) Operating and maintaining each of the CPMS used to measure scrubber water flow rate and pH according to § 63.9632(g) and recording all information needed to document conformance with these requirements.

(iii) Collecting and reducing monitoring data for scrubber water flow rate and pH according to § 63.9632(c) and recording all information needed to document conformance with these requirements.

(iv) If the daily average scrubber water flow rate or daily average pH is below the operating limits established for control device, you must follow the corrective action procedures in paragraph (l) of this section.

(2) For each DSI subject to the operating limits for sorbent injection rate and carrier gas flow rate in § 63.9590(b)(7), you must demonstrate continuous compliance by completing the requirements of paragraphs (i)(2)(i) through (iv) of this section.

(i) Maintain the daily average sorbent injection rate and carrier gas flow rate at or above the minimum level established during the most recent performance test.

(ii) Operate and maintain each CPMS used to measure the sorbent injection rate according to § 63.9632(h) and the carrier gas flow rate according to § 63.9632(i) and recording all information needed to document compliance with these requirements.

(iii) Collect and reduce monitoring data for the sorbent injection rate and carrier gas flow rate according to § 63.9632(c) and recording all information needed to document compliance with these requirements.

(iv) If the daily average the sorbent injection rate or carrier gas flow rate is below the operating limit established for the control device, you must follow the corrective action procedures in paragraph (l) of this section.

(j) For each affected indurating furnace using ACI to comply with the mercury emission limit in table 2 to this subpart, you must demonstrate continuous compliance by meeting the requirements of paragraphs (j)(1) or (2) of this section.

(1) If you use CEMS to demonstrate compliance, you must comply with the requirements in paragraphs (j)(1)(i) and (ii) of this section.

(i) You must operate a mercury CEMS in accordance with performance specification 12A at 40 CFR part 60, appendix B; these monitoring systems must be quality assured according to procedure 5 of 40 CFR 60, appendix F. You must demonstrate compliance with the mercury emissions limit using a 30-day rolling average of these 1-hour mercury concentrations or mass emissions rates, including CEMS data during startup and shutdown as defined in this subpart, calculated using equation 19–19 in section 12.4.1 of EPA Reference Method 19 at 40 CFR part 60, appendix A–7 of this part.

(ii) Owners or operators using a mercury CEMS to determine mass emission rate 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 specification 6 at 40 CFR part 60, appendix B and conducting an annual relative accuracy test of the continuous emission rate monitoring system according to section 8.2 of performance specification 6.

(2) If you do not use CEMS to demonstrate compliance, you must demonstrate continuous compliance by meeting the requirements of paragraphs (j)(2)(i) through (iv) of this section.

(i) Maintain the daily average activated carbon injection rate and carrier gas flow rate at or above the minimum level established during the most recent performance test.

(ii) Operate and maintain each CPMS used to measure the activated carbon injection rate according to § 63.9632(h) and the carrier gas flow rate according to § 63.9632(i), and record all information needed to document compliance with these requirements.

(iii) Collect and reduce monitoring data for the activated carbon injection rate and carrier gas flow rate according to § 63.9632(c) and record all information needed to document conformance with these requirements.

(iv) If the daily average of the activated carbon injection rate or carrier gas flow rate is below the operating limit established for the control device, you must follow the corrective action procedures in paragraph (l) of this section.

(k) If you use an air pollution control device other than a wet scrubber, dynamic wet scrubber, dry ESP, wet ESP, DSI, ACI, or baghouse, you must submit a site-specific monitoring plan in accordance with § 63.9631(f). The site-specific monitoring plan must include the site-specific procedures for demonstrating initial and continuous compliance with the corresponding operating limits.

(l) If the daily average operating parameter value for an emission unit or group of similar emission units does not meet the corresponding established operating limit, you must then follow the procedures in paragraphs (l)(1) through (4) of this section.

(1) You must initiate and complete initial corrective action within 10 calendar days and demonstrate that the initial corrective action was successful. During any period of corrective action, you must continue to monitor, and record all required operating parameters for equipment that remains in operation. After the initial corrective action, if the daily average operating parameter value for the emission unit or group of similar emission units meets the operating limit established for the corresponding unit or group, then the corrective action was successful and the emission unit or group of similar emission units is in compliance with the established operating limits.

(2) If the initial corrective action required in paragraph (l)(1) of this section was not successful, then you must complete additional corrective action within 10 calendar days and demonstrate that the subsequent corrective action was successful. During any period of corrective action, you must continue to monitor, and record all required operating parameters for equipment that remains in operation. If the daily average operating parameter value for the emission unit or group of similar emission units meets the operating limit established for the corresponding unit or group, then the corrective action was successful, and the emission unit or group of similar emission units is in compliance with the established operating limits.

(3) If the second attempt at corrective action required in paragraph (l)(2) of this section was not successful, then you must repeat the procedures of paragraph (l)(2) of this section until the corrective action is successful. If the third attempt at corrective action is unsuccessful, you must conduct another performance test in accordance with the procedures in § 63.9622(f) and report to the Administrator as a deviation the third unsuccessful attempt at corrective action.

(4) After the third unsuccessful attempt at corrective action, you must submit to the Administrator the written report required in paragraph (l)(3) of this section within 5 calendar days after the third unsuccessful attempt at corrective action. This report must notify the Administrator that a deviation has occurred and document the types of corrective measures taken to address the problem that resulted in the deviation of established operating parameters and the resulting operating limits.

(m) If you elect to comply with the mercury limit in table 2 to this subpart using emissions averaging in accordance with an implementation plan approved under the provisions in § 63.9623(d), you must comply with the requirements in paragraphs (m)(1) through (5) of this section.

(1) For furnaces included in the emissions averaging group that do not use mercury CEMS, you must comply with the requirements in paragraph (m)(1)(i) or (ii) as applicable.

(i) For furnaces equipped with ACI systems, you must comply with the requirements in paragraph (j) of this section.

(ii) For furnaces equipped with a mercury control device or method other than ACI, you must comply with your site-specific monitoring plan in accordance with the requirements in paragraph (k) of this section.

(2) For furnaces included in the emissions averaging group that use mercury CEMS, you must comply with the requirements in paragraph (i)(1) of this section.

(3) Calculate the monthly production-weighted average emission rate using either the mercury CEMS data or mercury emission rate determined during the last performance test and the actual taconite pellet production data for each furnace included in the emissions averaging option, as shown in Equation 6 of this section.

$$E_g = \frac{\sum_{f=1}^{n}(E_f \times P_f)}{\sum_{f=1}^{n} P_f} \quad (Eq. 6)$$

Where:

E_g = Monthly production-weighted average mercury emission rate for month “g” for the group of indurating furnaces, lb/LT of pellets produced,

E_f = Average mercury emission rate for furnace “f”, as determined using either mercury CEMS data or the emission rate determined during the last compliance stack test and calculated using Equation 5 of § 63.9621(d)(7)(i), lb/LT of pellets produced,

P_f = Total monthly production of finished taconite pellets for furnace “f”, in LT, and

n = Number of furnaces in the averaging group.

(4) Until 12 monthly weighted average emission rates have been accumulated, the monthly weighted average emissions rate, calculated as shown in paragraph (m)(3) of this section, must not exceed the mercury emission limit in table 3 of this subpart in any calendar month.

(5) After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, you must use Equation 7 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current month and the previous 11 months. The 12-month rolling weighted average emissions rate for the furnaces included in the group must not exceed the mercury emission limit in table 3 of this subpart.

$$E_{avg} = \frac{\sum_{i=1}^{12} E_i}{12} \quad Eq. 7$$

Where:

E_{avg} = 12-month rolling average emission rate, lb/LT.

E_i = Monthly weighted average for month “i” calculated as shown in Equation 6 of this section.

(n) You may elect to demonstrate continuous compliance with the mercury limit in table 2 to this subpart by adjusting the activated carbon injection rate based on the taconite pellet production rate. You must comply with the requirements in paragraphs (n)(1) through (7) of this section.

(1) Measure the activated carbon injection and mercury emissions rate at a minimum of three different production levels corresponding to the maximum, minimum and median finished taconite pellet production rates, using the methods specified in § 63.9620(k).

(2) Develop a correlation curve by plotting the production rate and corresponding carbon injection rate for the maximum, median and minimum production rates. Use only data where the mercury emission rate is below the applicable mercury emissions standard in table 2 to this subpart. Plot the production rates as the independent (or x) variable and the activated carbon injection rate as the dependent (or y) variable for each pellet production rate. Construct the graph by drawing straight line segments between each point plotted.

(3) You must develop and submit to the applicable regulatory authority for review and approval, an implementation plan no later than 180 days before the date you intend to demonstrate compliance by adjusting the activated carbon injection rate based on the taconite pellet production. You must include the information listed in paragraphs (n)(3)(i) through (iv) of this section in your implementation plan.

(i) Identification of the indurating furnace, including the typical maximum and minimum taconite pellet production rate, mercury control technology installed, and types of fuel(s) that will be burned.

(ii) The mercury emissions and activated carbon injection rates at maximum, median and minimum taconite pellet production rates, and the methods used to measure the mercury emissions, activated carbon injection rate and taconite pellet production.

(iii) The correlation curve developed in paragraph (n)(2) of this section.

(iv) The date on which you are requesting to commence adjusting the activated carbon rate based on the taconite production rate.

(4) Install, calibrate, maintain, and operate a CPMS to monitor and record the activated carbon injection rate and taconite pellet production rate.

(5) Maintain the carbon injection rate at or above the rate established by the correlation curve corresponding to the taconite pellet production rate. If the taconite pellet production rate drops below the minimum rate established in paragraph (n)(3) of this section, you must maintain the activated carbon injection rate at or above the rate established for the minimum taconite pellet production rate.

(6) Keep records of the activated carbon injection rate and taconite pellet production rate for each hour of operation in order to demonstrate that the activated carbon injection rate remains in compliance with paragraph (n)(5) of this section.

(7) Establish a new correlation curve at least twice per 5-year permit term.

■ 15. Section 63.9636 is amended by revising paragraph (a) introductory text to read as follows:

§ 63.9636 How do I demonstrate continuous compliance with the operation and maintenance requirements that apply to me?

(a) For each control device used to comply with an emission standard in § 63.9590(a), you must demonstrate continuous compliance with the operation and maintenance requirements in § 63.9600(b) by completing the requirements of paragraphs (a)(1) through (4) of this section.

* * * * *

■ 16. Section 63.9637 is amended by revising paragraph (a) to read as follows:

§ 63.9637 What other requirements must I meet to demonstrate continuous compliance?

(a) *Deviations.* You must report each instance in which you did not meet each emission limitation in tables 1 through 3 to this subpart that applies to you. You also must report each instance in which you did not meet the work practice standards in § 63.9591 and each instance in which you did not meet each operation and maintenance requirement in § 63.9600 that applies to you. These instances are deviations from the emission limitations, work practice standards, and operation and maintenance requirements in this subpart. These deviations must be reported in accordance with the requirements in § 63.9641.

* * * * *

■ 17. Section 63.9640 is amended by adding paragraphs (f) and (g) to read as follows:

§ 63.9640 What notifications must I submit and when?

* * * * *

(f) If you elect to use CEMS to demonstrate compliance with the mercury standards in table 2 to this subpart, you must submit a notification of intent to use CEMS at least one month prior to making the change. If you are currently using CEMS to demonstrate compliance with the mercury standards, you must submit a notification of intent to cease using CEMS to demonstrate compliance at least 180 days prior to making the change.

(g) If you elect to use the mercury emissions averaging compliance option, you must submit a notification of intent at least 180 days prior to making the change. If you are currently using the mercury emissions averaging compliance option, you must submit a notification of intent to cease using emissions averaging at least 30 days prior to making the change.

■ 18. Section 63.9641 is amended by:

■ a. Revising paragraph (b)(6);

■ b. Revising and republishing paragraph (b)(8);

■ c. Revising paragraphs (c), (e) and (f)(3); and

■ d. Adding paragraph (i).

The revisions and additions read as follows:

§ 63.9641 What reports must I submit and when?

* * * * *

(b) * * *

(6) If there were no periods during which a continuous monitoring system (including a CPMS, COMS, or CEMS) was out-of-control as specified in § 63.8(c)(7), then provide a statement that there were no periods during which a continuous monitoring system was out-of-control during the reporting period.

* * * * *

(8) On or before January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, for each deviation from an emission limitation occurring at an affected source where you are using a continuous monitoring system (including a CPMS or COMS) to comply with the emission limitation in this subpart, you must include the information in paragraphs (b)(1) through (4) of this section and the information in paragraphs (b)(8)(i) through (xi) of this section. This includes periods of startup, shutdown, and malfunction. After January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, and after July 28, 2020, or upon start-up, which ever date is later, for affected sources that commenced construction or reconstruction after September 25, 2019, for each deviation from an emission limitation occurring at an affected source where you are using a continuous monitoring system (including a CPMS, COMS, or CEMS) to comply with the emission limitation in this subpart, you must include the information in paragraphs (b)(1) through

(4) of this section and the information in paragraphs (b)(8)(i) through (xi) of this section.

(i) The date and time that each malfunction started and stopped.

(ii) The start date, start time, and duration in hours (or minutes for COMS) that each continuous monitoring system was inoperative, except for zero (low-level) and high-level checks.

(iii) The start date, start time, and duration that each continuous monitoring system was out-of-control, including the information in § 63.8(c)(8).

(iv) On or before January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, for each affected source or equipment, the date and time that each deviation started and stopped, the cause of the deviation, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period. After January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, and after July 28, 2020, or upon start-up, which ever date is later, for affected sources that commenced construction or reconstruction after September 25, 2019, for each affected source or equipment, the date and time that each deviation started and stopped, the cause of the deviation, and whether each deviation occurred during a period of malfunction or during another period

(v) The total duration of all deviations for each Continuous Monitoring System (CMS) during the reporting period, the total operating time in hours of the affected source during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(vi) On or before January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, a breakdown of the total duration of the deviations during the reporting period including those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes. After January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, and after July 28, 2020, or upon start-up, which ever date is later, for affected sources that commenced construction or reconstruction after September 25, 2019, a breakdown of the total duration of the deviations during the reporting period including those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(vii) The total duration of continuous monitoring system downtime for each continuous monitoring system during the reporting period, the total operating time in hours of the affected source during the reporting period, and the total duration of continuous monitoring system downtime as a percent of the total source operating time during the reporting period.

(viii) A brief description of the process units.

(ix) The monitoring equipment manufacturer and model number and the pollutant or parameter monitored.

(x) The date of the latest continuous monitoring system certification or audit.

(xi) A description of any changes in continuous monitoring systems, processes, or controls since the last reporting period.

(c) *Submitting compliance reports electronically.* Beginning on January 25, 2021, submit all subsequent compliance reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as confidential business information (CBI). Anything submitted using CEDRI cannot later be claimed to be CBI. You must use the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/compliance-and-emissions-data-reporting-interface-cedri*) for this subpart. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. Although we do not expect persons to assert a claim of CBI, if persons wish to assert a CBI claim, submit a complete report, including information claimed to be CBI, to the EPA. The report must be generated using the appropriate form on the CEDRI website. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Submit the file following the procedures in paragraph (c)(1) or (2) of this section. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (c). All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c) emissions data is not entitled to confidential treatment, and EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. On or before January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan you must submit an immediate startup, shutdown and malfunction report according to the requirements in § 63.10(d)(5)(ii). After January 25, 2021, for affected sources that commenced construction or reconstruction on or before September 25, 2019, and after July 28, 2020, or upon start-up, which ever date is later, for affected sources that commenced construction or reconstruction after September 25, 2019, an immediate startup, shutdown, and malfunction report is not required.

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described above, should include clear CBI markings and be flagged to the attention of the Taconite Iron Ore Processing Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer and Taconite Iron Ore Processing Sector Lead, Mail Drop: C404–02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

* * * * *

(e) *Immediate corrective action report.* If you had three unsuccessful attempts of applying corrective action as described in § 63.9634(l) on an emission unit or group of emission units, then you must submit an immediate corrective action report. Within 5 calendar days after the third unsuccessful attempt at corrective action, you must submit to the Administrator a written report in accordance with § 63.9634(l)(3) and (4). This report must notify the Administrator that a deviation has occurred and document the types of corrective measures taken to address the problem that resulted in the deviation of established operating parameters and the resulting operating limits.

(f) * * *

(3) *Confidential business information (CBI).*

(i) The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (f)(1) or (2) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA.

(ii) The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website.

(iii) Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

(iv) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described above, should include clear CBI markings and be flagged to the attention of the Group Leader, Measurement Policy Group. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(v) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer and Measurement Policy Group Lead, Mail Drop: C404–02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(vi) All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(vii) You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described in § 63.9(k).

* * * * *

(i) *Use of CEMS for mercury.* If you use CEMS to demonstrate compliance with the mercury emissions limits in table 2 to this subpart, you must submit the results of the performance evaluation following the procedure specified in either paragraph (i)(1) or (2) of this section within 60 days after the date of completing each CEMS performance evaluation (as defined in § 63.2).

(1) 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 website at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. 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 website. 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 website, 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/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 section.

(2) 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 website 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.

■ 19. Section 63.9642 is amended by:

■ a. Revising paragraph (b) introductory text; and

■ b. Adding paragraphs (b)(5), (d), (e) and (f).

The revisions and additions read as follows:

§ 63.9642 What records must I keep?

* * * * *

(b) For each COMS and CEMS, you must keep the records specified in paragraphs (b)(1) through (5) of this section.

* * * * *

(5) If you use mercury CEMS to demonstrate compliance with the mercury emission standard in table 2 of the subpart in accordance with § 63.9623(e), records of requests for alternatives to the relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

* * * * *

(d) If you elect the mercury emissions averaging compliance alternative pursuant to § 63.9623(d), you must keep a copy of the emission averaging implementation plan required in § 63.9623(d)(2), records of the taconite pellet production rate for each furnace included in the averaging, and all calculations required under § 63.9634(m).

(e) If you elect to adjust the activated carbon injection rate based on the taconite pellet production rate in accordance with the provisions in § 63.9634(n), you must keep a copy of the activated carbon injection implementation plan and records of the taconite pellet production rate and activated carbon injection rate.

(f) If you use CEMS to demonstrate compliance with the mercury emissions limits in table 2 to this subpart, you must keep records of the notifications required in § 63.9642(f).

■ 20. Section 63.9650 is revised to read as follows:

§ 63.9650 What parts of the General Provisions apply to me?

Table 4 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.16 apply to you.

■ 21. Section 63.9652 is amended by adding definitions in alphabetical order for ''Activated carbon injection (ACI) system'', ''Dry sorbent injection (DSI) system'', and ''Electrostatic precipitator (ESP)'' to read as follows:

§ 63.9652 What definitions apply to this subpart?

* * * * *

Activated carbon injection (ACI) system means an add-on air pollution control system in which activated carbon or brominated activated carbon is injected into the flue gas steam upstream of a particulate matter control device to adsorb mercury in the exhaust stream. The absorbed mercury remains absorbed to the activated carbon and is collected in a primary or secondary particulate matter control device.

* * * * *

Dry sorbent injection (DSI) system 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 that is collected by a primary or secondary particulate matter control device.

* * * * *

Electrostatic Precipitator (ESP) means a device that removes suspended particulate matter from flue exhaust by applying a high-voltage electrostatic charge to the particles, which are then attracted to and collected on a grounded plate. In a dry ESP, the particles are dislodged from the plate by rapping and are collected in a hopper positioned below the plate. In a wet ESP, particulates are removed from the plate by washing with water.

* * * * *

■ 22. Revise the table heading and introductory paragraph for table 1 to subpart RRRRR of part 63 to read as follows:

Table 1 to Subpart RRRRR of Part 63—Particulate Matter Emission Limits

As required in § 63.9590(a), you must comply with each applicable particulate matter emission limit in the following table:

* * * * *

■ 22. Table 2 to subpart RRRRR is redesignated as table 4 to subpart RRRRR.

■ 23. Add a new table 2 to subpart RRRRR to read as follows:

Table 2 to Subpart RRRRR of Part 63—Mercury Emission Limits for Indurating Furnaces

[As required in § 63.9590(a), you must comply with each applicable mercury emission limit in the following table:]

For . . .	You must meet the following emission limits . . .
1. Indurating furnaces constructed or reconstructed before May 15, 2023.	Either: (1) Mercury emissions from each furnace must not exceed 1.4×10^{-5} lb/LT of taconite pellets produced, or (2) Production-weighted average mercury emissions for a group of indurating furnaces, calculated according to Equation 6 in § 63.9634(m)(3), must not exceed 1.3×10^{-5} lb/LT.
2. Indurating furnaces constructed or reconstructed on or after May 15, 2023.	Mercury emissions from each furnace must not exceed 2.6×10^{-6} lb/LT.

■ 24. Add Table 3 to Subpart RRRRR to read as follows:

Table 3 to Subpart RRRRR of Part 63—Hydrogen Chloride and Hydrogen Fluoride Emission Limits for Indurating Furnaces

[As required in § 63.9590(a), you must comply with each applicable hydrogen chloride and hydrogen fluoride emission limit in the following table:]

For . . .	You must meet the following emission limits . . .
1. Indurating furnaces constructed or reconstructed before May 15, 2023.	Hydrogen chloride emissions must not exceed 4.6×10^{-2} lb/Long Ton of taconite pellets produced. Hydrogen fluoride emissions must not exceed 1.2×10^{-2} lb/Long Ton of taconite pellets produced.
2. Indurating furnaces constructed or reconstructed on or after May 15, 2023.	Hydrogen chloride emissions must not exceed 4.4×10^{-4} lb/Long Ton of taconite pellets produced Hydrogen fluoride emissions must not exceed 3.3×10^{-4} lb/Long Ton of taconite pellets produced.

■ 25. Revise newly redesignated table 4 to subpart RRRRR to read as follows:

Table 4 to Subpart RRRRR of Part 63—Applicability of General Provisions to Subpart RRRRR of Part 63

[As required in § 63.9650, you must comply with the requirements of the NESHAP General Provisions (40 CFR part 63, subpart A) shown in the following table:]

Citation	Summary of requirement	Am I subject to this requirement?	Explanations
§ 63.1(a)(1)–(4)	Applicability	Yes.	
§ 63.1(a)(5)	[Reserved]	No.	
§ 63.1(a)(6)	Applicability	Yes.	
§ 63.1(a)(7)–(9)	[Reserved]	No.	
§ 63.1(a)(10)–(14)	Applicability	Yes.	
§ 63.1(b)(1)	Initial Applicability Determination	Yes.	
§ 63.1(b)(2)	[Reserved]	No.	
§ 63.1(b)(3)	Initial Applicability Determination	Yes.	
§ 63.1(c)(1)–(2)	Applicability After Standard Established, Permit Requirements.	Yes.	

TABLE 4 TO SUBPART RRRRR OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART RRRRR OF PART 63—Continued

[As required in § 63.9650, you must comply with the requirements of the NESHAP General Provisions (40 CFR part 63, subpart A) shown in the following table:]

Citation	Summary of requirement	Am I subject to this requirement?	Explanations
§ 63.1(c)(3)–(4)	[Reserved]	No.	
§ 63.1(c)(5)	Area Source Becomes Major	Yes.	
§ 63.1(c)(6)	Reclassification	Yes.	
§ 63.1(d)	[Reserved]	No.	
§ 63.1(e)	Equivalency of Permit Limits	Yes.	
§ 63.2	Definitions	Yes.	
§ 63.3(a)–(c)	Units and Abbreviations	Yes.	
§ 63.4(a)(1)–(2)	Prohibited Activities	Yes.	
§ 63.4(a)(3)–(5)	[Reserved]	No.	
§ 63.4(b)–(c)	Circumvention, Fragmentation	Yes.	
§ 63.5(a)(1)–(2)	Construction/Reconstruction, Applicability.	Yes.	
§ 63.5(b)(1)	Construction/Reconstruction, Applicability.	Yes.	
§ 63.5(b)(2)	[Reserved]	No.	
§ 63.5(b)(3)–(4)	Construction/Reconstruction, Applicability.	Yes.	
§ 63.5(b)(5)	[Reserved]	No.	
§ 63.5(b)(6)	Applicability	Yes.	
§ 63.5(c)	[Reserved]	No.	
§ 63.5(d)(1)–(4)	Application for Approval of Construction or Reconstruction.	Yes.	
§ 63.5(e)	Approval of Construction or Reconstruction.	Yes.	
§ 63.5(f)	Approval Based on State Review	Yes.	
§ 63.6(a)	Compliance with Standards and Maintenance Requirements.	Yes.	
§ 63.6(b)(1)–(5)	Compliance Dates for New/Reconstructed Sources.	Yes.	
§ 63.6(b)(6)	[Reserved]	No.	
§ 63.6(b)(7)	Compliance Dates for New/Reconstructed Sources.	Yes.	
§ 63.6(c)(1)–(2)	Compliance Dates for Existing Sources.	Yes.	
§ 63.6(c)(3)–(4)	[Reserved]	No.	
§ 63.6(c)(5)	Compliance Dates for Existing Sources.	Yes.	
§ 63.6(d)	[Reserved]	No.	
§ 63.6(e)(1)(i)	Operation and Maintenance Requirements—General Duty to Minimize Emissions.	Yes, on or before the compliance date specified in § 63.9600(a). No, after the compliance date specified in § 63.9600(a).	See § 63.9600(a) for general duty requirement.
§ 63.6(e)(1)(ii)	Operation and Maintenance Requirements—Requirement to Correct Malfunction as Soon as Possible.	No.	
§ 63.6(e)(1)(iii)	Operation and Maintenance Requirements—Enforceability.	Yes.	
§ 63.6(e)(2)	[Reserved]	No.	
§ 63.6(e)(3)	Startup, Shutdown, Malfunction (SSM) Plan.	Yes, on or before the compliance date specified in § 63.9610(c). No, after the compliance date specified in § 63.9610(c).	
§ 63.6(f)(1)	SSM exemption	No	See § 63.9600(a).
§ 63.6(f)(2)–(3)	Methods for Determining Compliance	Yes.	
§ 63.6(g)(1)–(3)	Alternative Nonopacity Standard	Yes.	
§ 63.6(h), except (h)(1).	Compliance with Opacity and Visible Emission (VE) Standards.	No	Opacity limits in subpart RRRRR are established as part of performance testing in order to set operating limits for ESPs.
§ 63.6(h)(1)	Compliance except during SSM	No	See § 63.9600(a).
§ 63.6(i)(1)–(14)	Extension of Compliance	Yes.	
§ 63.6(i)(15)	[Reserved]	No.	
§ 63.6(i)(16)	Extension of Compliance	Yes.	
§ 63.6(j)	Presidential Compliance Exemption	Yes.	
§ 63.7(a)(1)–(2)	Applicability and Performance Test Dates.	No	Subpart RRRRR specifies performance test applicability and dates.
§ 63.7(a)(3)–(4)	Performance Testing Requirements	Yes.	
§ 63.7(b)	Notification	Yes.	
§ 63.7(c)	Quality Assurance/Test Plan	Yes.	

TABLE 4 TO SUBPART RRRRR OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART RRRRR OF PART 63—Continued

[As required in § 63.9650, you must comply with the requirements of the NESHAP General Provisions (40 CFR part 63, subpart A) shown in the following table:]

Citation	Summary of requirement	Am I subject to this requirement?	Explanations
§ 63.7(d)	Testing Facilities	Yes.	
§ 63.7(e)(1)	Conduct of Performance Tests	No	See § 63.9621.
§ 63.7(e)(2)–(4)	Conduct of Performance Tests	Yes.	
§ 63.7(f)	Alternative Test Method	Yes.	
§ 63.7(g)	Data Analysis	Yes	Except this subpart specifies how and when the performance test results are reported.
§ 63.7(h)	Waiver of Tests	Yes.	
§ 63.8(a)(1)–(2)	Monitoring Requirements	Yes.	
§ 63.8(a)(3)	[Reserved]	No.	
§ 63.8(a)(4)	Additional Monitoring Requirements for Control Devices in § 63.11.	No	Subpart RRRRR does not require flares.
§ 63.8(b)(1)–(3)	Conduct of Monitoring	Yes.	
§ 63.8(c)(1)(i)	Operation and Maintenance of CMS	Yes, on or before the compliance date specified in § 63.9632(b)(4). No, after the compliance date specified in § 63.9632(b)(4).	See § 63.9632 for operation and maintenance requirements for monitoring. See § 63.9600(a) for general duty requirement.
§ 63.8(c)(1)(ii)	Spare parts for CMS Equipment	Yes.	
§ 63.8(c)(1)(iii)	SSM Plan for CMS	Yes, on or before the compliance date specified in § 63.9632(b)(4). No, after the compliance date specified in § 63.9632(b)(4).	
§ 63.8(c)(2)–(3)	CMS Operation/Maintenance	Yes.	
§ 63.8(c)(4)	Frequency of Operation for CMS	No	Subpart RRRRR specifies requirements for operation of CMS.
§ 63.8(c)(5)–(8)	CMS Requirements	Yes	CMS requirements in § 63.8(c)(5) and (6) apply only to COMS for dry ESPs.
§ 63.8(d)(1)–(2)	Monitoring Quality Control	Yes.	
§ 63.8(d)(3)	Monitoring Quality Control	No	See § 63.9632(b)(5).
§ 63.8(e)	Performance Evaluation for CMS	Yes.	
§ 63.8(f)(1)–(5)	Alternative Monitoring Method	Yes.	
§ 63.8(f)(6)	Relative Accuracy Test Alternative (RATA).	Yes	Only if using continuous emission monitoring systems to demonstrate compliance with Table 2 to this subpart.
§ 63.8(g)(1)–(g)(4)	Data Reduction	Yes.	
§ 63.8(g)(5)	Data That Cannot Be Used	No	Subpart RRRRR specifies data reduction requirements.
§ 63.9	Notification Requirements	Yes	Additional notifications for CMS in § 63.9(g) apply to COMS for dry ESPs.
§ 63.9(k)	Electronic reporting procedures	Yes	Only as specified in § 63.9(j)
§ 63.10(a)	Recordkeeping and Reporting, Applicability and General Information.	Yes.	
§ 63.10(b)(1)	General Recordkeeping Requirements	Yes.	
§ 63.10(b)(2)(i)	Records of SSM	No	See § 63.9642 for recordkeeping when there is a deviation from a standard.
§ 63.10(b)(2)(ii)	Recordkeeping of Failures to Meet a Standard.	No	See § 63.9642 for recordkeeping of (1) date, time and duration; (2) listing of affected source or equipment, and an estimate of the quantity of each regulated pollutant emitted over the standard; and (3) actions to minimize emissions and correct the failure.
§ 63.10(b)(2)(iii)	Maintenance Records	Yes.	
§ 63.10(b)(2)(iv)	Actions Taken to Minimize Emissions During SSM.	No.	
§ 63.10(b)(2)(v)	Actions Taken to Minimize Emissions During SSM.	No.	
§ 63.10(b)(2)(vi)	Recordkeeping for CMS Malfunctions	Yes.	
§ 63.10(b)(2)(vii)–(xii)	Recordkeeping for CMS	Yes.	
§ 63.10(b)(2)(xiii)	Records for Relative Accuracy Test	No.	
§ 63.10(b)(2)(xiv)	Records for Notification	Yes.	
§ 63.10(b)(3)	Applicability Determinations	Yes.	

TABLE 4 TO SUBPART RRRRR OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART RRRRR OF PART 63—Continued

[As required in § 63.9650, you must comply with the requirements of the NESHAP General Provisions (40 CFR part 63, subpart A) shown in the following table:]

Citation	Summary of requirement	Am I subject to this requirement?	Explanations
§ 63.10(c)(1)–(6)	Additional Recordkeeping Requirements for Sources with CMS.	Yes.	
§ 63.10(c)(7)–(8)	Records of Excess Emissions and Parameter Monitoring Exceedances for CMS.		Subpart RRRRR specifies recordkeeping requirements.
§ 63.10(c)(9)	[Reserved]	No.	
§ 63.10(c)(10)–(14)	CMS Recordkeeping	Yes.	
§ 63.10(c)(15)	Use of SSM Plan	No.	
§ 63.10(d)(1)–(2)	General Reporting Requirements	Yes	Except this subpart specifies how and when the performance test results are reported.
§ 63.10(d)(3)	Reporting opacity or VE observations	No	Subpart RRRRR does not have opacity and VE standards that require the use of EPA Method 9 of appendix A–4 to 40 CFR part 60 or EPA Method 22 of appendix A–7 to 40 CFR part 60.
§ 63.10(d)(5)	SSM Reports	Yes, on or before the compliance date specified in § 63.9641(b)(4). No, after the compliance date specified in § 63.9641(b)(4).	See § 63.9641 for malfunction reporting requirements.
§ 63.10(e)	Additional Reporting Requirements	Yes, except a breakdown of the total duration of excess emissions due to startup/shutdown in63.10(e)(3)(vi)(I) is not required and when the summary report is submitted through CEDRI, the report is not required to be titled "Summary Report-Gaseous and Opacity Excess Emission and Continuous Monitoring System Performance.".	The electronic reporting template combines the information from the summary report and excess emission report with the Subpart RRRRR compliance report.
§ 63.10(f)	Waiver for Recordkeeping or Reporting.	Yes.	
§ 63.11	Control Device and Work Practice Requirements.	No	Subpart RRRRR does not require flares.
§ 63.12(a)–(c)	State Authority and Delegations	Yes.	
§ 63.13(a)–(c)	State/Regional Addresses	Yes.	
§ 63.14(a)–(t)	Incorporation by Reference	Yes.	
§ 63.15(a)–(b)	Availability of Information and Confidentiality.	Yes.	
§ 63.16	Performance Track Provisions	Yes.	

[FR Doc. 2024–02305 Filed 3–5–24; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2020–0430; FRL–7522–02–OAR]

RIN 2060–AU63

National Emission Standards for Hazardous Air Pollutants: Primary Copper Smelting Residual Risk and Technology Review and Primary Copper Smelting Area Source Technology Review

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes the residual risk and technology review (RTR) conducted for the Primary Copper Smelting major source category regulated under national emission standards for hazardous air pollutants (NESHAP). This action also finalizes the technology review for the Primary Copper Smelting area source NESHAP. The final amendments for the major source NESHAP include particulate matter (PM) emission standards as a surrogate for metal hazardous air pollutants (HAP) other than mercury (primarily lead and arsenic) for anode refining point sources, process fugitive emissions from roofline vents, Hoboken converter process fugitive capture systems where they combine with anode refining point sources, and new converters. We are also finalizing emission standards for previously unregulated HAP including mercury, benzene, toluene, hydrogen chloride (HCl), chlorine, polycyclic aromatic hydrocarbons (PAH), and dioxins and furans (D/F). In addition, we are taking final action in the major source NESHAP to establish work practice standards for bypass stacks, and add a new emissions limit for lead and emissions control design standards to minimize process fugitive emissions at facilities with flash furnaces and Peirce-Smith converters. Final amendments for both the major source NESHAP and the area source NESHAP include removing exemptions and associated provisions for periods of startup, shutdown, and malfunction (SSM), specifying that the emission standards apply at all times, and requiring electronic reporting of performance test results and notification of compliance reports.

DATES: This final rule is effective May 13, 2024, except for amendatory instruction 3, which is effective July 15, 2024. The incorporation by reference (IBR) of certain publications listed in the rule is approved by the Director of the Federal Register as of May 13, 2024.

ADDRESSES: The U.S. Environmental Protection Agency (EPA) has established a docket for this action under Docket ID No. EPA–HQ–OAR–2020–0430. All documents in the docket are listed on the *https://www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.*, Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *https://www.regulations.gov/*, or in hard copy at the EPA Docket Center, WJC West Building, Room Number 3334, 1301 Constitution Ave. NW, Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact U.S. EPA, Attn: Amanda Hansen, Mail Drop: D243–04, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, North Carolina 27711; telephone number: (919) 541–3165; email address: *hansen.amanda@epa.gov.* For specific information regarding the risk modeling methodology, contact U.S. EPA, Attn: James Hirtz, Mail Drop: C539–02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, North Carolina 27711; telephone number: (919) 541–0881; email address: *hirtz.james@epa.gov.*

SUPPLEMENTARY INFORMATION: Preamble acronyms and abbreviations. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACI	activated carbon injection
ADEQ	Arizona Department of Environmental Quality
ANSI	American National Standards Institute
BTF	beyond-the-floor
CAA	Clean Air Act
CEDRI	Compliance and Emissions Data Reporting Interface
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CRA	Congressional Review Act
CMS	continuous monitoring systems
DCOT	digital camera opacity technique
D/F	dioxins and furans
DSI	dry sorbent injection
EAF	electric arc furnaces
EJ	Environmental Justice
EPA	Environmental Protection Agency
ERT	Electronic Reporting Tool
FEM	Federal equivalent method
FR	Federal Register
FRM	Federal reference method
GACT	generally available control technology
gr/dscf	grains per dry standard cubic feet
HAP	hazardous air pollutants
HCl	hydrogen chloride
HEM–4	Human Exposure Model, Version 1.5.5
HI	hazard index
HQ	hazard quotient
ICR	information collection request
lbs	pounds
lb/hr	pounds per hour
LEAN	Louisiana Environmental Action Network
MACT	maximum achievable control technology
mg/dscm	milligrams per dry standard cubic meter
MIR	maximum individual risk
MTG	Measurement Technology Group
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NTTAA	National Technology Transfer and Advancement Act
OAR	Office of Air and Radiation
OMB	Office of Management and Budget
PAH	polycyclic aromatic hydrocarbons
Pb	lead
PDF	portable document format
PM	particulate matter
PRA	Paperwork Reduction Act
RATA	Relative Accuracy Test Audit
REL	reference exposure level
RFA	Regulatory Flexibility Act
RIN	Regulatory Information Number
RTR	risk and technology review
SIP	state implementation plan
SO_2	sulfur dioxide
SSM	startup, shutdown, and malfunction
TEQ	toxic equivalency quotient
TOSHI	target organ-specific hazard index
tpy	ton per year
ug/m³	micrograms per cubic meter
UMRA	Unfunded Mandates Reform Act
UPL	upper prediction limit
VCS	voluntary consensus standards
WESP	wet electrostatic precipitator

Background information. On January 11, 2022 (87 FR 1616), and July 24, 2023 (88 FR 47415), the EPA proposed revisions to the Primary Copper Smelting major source NESHAP based on our RTR. In this action, we are finalizing decisions and revisions for the major source rule. On January 11, 2022 (87 FR 1616), the EPA also proposed revisions to the Primary Copper Smelting area source NESHAP based on our technology review. In this action, we are also finalizing decisions and revisions for the area source rule.

We summarize some of the more significant comments we timely received regarding the proposed rules and provide our responses in this preamble. A summary of all other public comments on the proposals and the EPA's responses to those comments is available in *National Emission Standards for Hazardous Air Pollutant Emissions: Primary Copper Smelting Residual Risk and Technology Review and Primary Copper Smelting Area Source Technology Review: Summary of Public Comments and Responses*, Docket ID No. EPA–HQ–OAR–2020–0430. ''Track changes'' versions of the regulatory language that incorporate the changes to the two rules in this action are available in the docket.

Organization of this document. The information in this preamble is organized as follows:

I. General Information

A. Executive Summary

This action presents the results of the U.S. Environmental Protection Agency (EPA or the Agency) residual risk and technology review (RTR) for the National Emission Standards for Hazardous Air Pollutants (NESHAP) for major source Primary Copper Smelters as required under the Clean Air Act (CAA). Pursuant to the CAA, this action also presents the results of the technology review for the Primary Copper Smelting area source NESHAP.

Based on the results of the risk review, the EPA is finalizing a determination that risks from emissions of air toxics from this major source category are currently unacceptable. This unacceptable risk determination considers all health information, including the EPA's analysis of health risks associated with emissions of lead and arsenic from these facilities. The modeled exceedance of the lead National Ambient Air Quality Standard (NAAQS) of 0.15 ug/m^3 at Freeport represents an important health metric in EPA's unacceptability determination for the Primary Copper source category. The EPA estimated that the highest modeled rolling 3-month concentration of lead at a residential location is 0.17 ug/m^3 based on 2019 actual emissions and 0.24 ug/m^3 based on allowable emissions, at the Freeport facility, refer to appendix 1; section 9 of the *Residual Risk Assessment for the Primary Copper Smelting Source Category in Support of the 2021 Risk and Technology Review Proposed Rule* for additional details of the monitor to model comparison for this rule. The NAAQS off-site lead (Pb) monitor (at Miami Golf Course) recorded Pb levels for 2019 were below the NAAQS with a maximum 3-month Pb concentration at the monitor of 0.038 ug/m^3, while the modeled Pb concentration based upon actual emissions for this site was 0.045 ug/m^3. This close alignment of the monitor with model results for the Miami Golf Course site provides us with additional confidence in our maximum off-site model concentration of 0.17 ug/m^3 at a residential location. The EPA also found that the maximum individual risk (MIR) of cancer was estimated to be 70-in-1 million based on actual emissions and 90-in-1 million based on allowable emissions (driven by arsenic emissions), which is approaching the presumptive level of unacceptability of 100-in-1 million. In addition, the EPA found that the maximum acute hazard quotient (HQ) was 7 (also driven by arsenic emissions). Considering all of the health risk information and factors discussed above, along with the risk information and uncertainties discussed in the 2022 proposed rule preamble (87 FR 1616), the EPA has determined that the current risks for this source category are unacceptable.

To reduce risks to an acceptable level, the EPA is finalizing a new emission limit for particulate matter (PM) as a surrogate for particulate hazardous air pollutant (HAP) metals (such as lead and arsenic) in the major source NESHAP for a combination of process fugitive roofline emissions from the anode refining department, copper converter departments, slag cleaning vessels and smelting vessels (also known as smelting furnaces). This standard will achieve significant reductions of lead and arsenic emissions and their associated health risks (as described in section IV.A. of this preamble).

Pursuant to the *LEAN* decision (which is described further in section II.A. of this preamble), the EPA is also finalizing new emissions standards based on maximum achievable control technology (MACT) for the major source NESHAP to address currently unregulated emissions of HAP, as follows: PM, as a surrogate for particulate HAP metals, for (1) anode refining furnace point source emissions; (2) new converters; and (3) the combination of process fugitive roofline emissions from the anode refining department, copper converter departments, slag cleaning vessels and smelting vessels (also known as smelting furnaces). The EPA is also finalizing new pollutant-specific emissions limits based on MACT for the following HAP: mercury, lead, benzene, toluene, hydrogen chloride (HCl), chlorine, polycyclic aromatic hydrocarbons (PAH), naphthalene and dioxins and furans (D/F). Furthermore, in this final action, after reviewing and considering public comments, the EPA is finalizing work practice standards according to CAA 112(h) for bypass stacks which were previously an unregulated emissions source.

Pursuant to the CAA mandated technology review, we are finalizing a PM limit (as a surrogate for nonmercury metal HAP) for the combined emissions from the Hoboken converter process fugitive capture systems where they combine with anode refining point source emissions. This standard will achieve significant reductions of lead and arsenic emissions (as described in sections III.B. and IV.B. of this preamble). Furthermore, we are finalizing emissions control design standards to minimize process fugitive HAP metals emissions from roof vents at facilities with flash furnaces and Peirce-Smith converters. In addition, under the technology review the EPA is finalizing work practice standards to minimize fugitive dust emissions which will achieve further emissions reductions beyond the reductions that will be achieved from the rooflines under the risk review for major sources (described above).

With regard to primary copper smelting area sources, the Agency did not identify any developments in practices, processes, or control technologies. Therefore, the EPA is not finalizing any new or revised standards pursuant to the CAA technology review for the area source NESHAP.

In addition to the new and revised standards described in the previous paragraphs, consistent with *Sierra Club* v. *EPA* (which is described further in section III.D. of this preamble), the EPA is also finalizing rule changes to remove exemptions and associated provisions for periods of startup, shutdown, and malfunction (SSM) and to specify that the emission standards apply at all times. The EPA is also finalizing rule changes to require electronic reporting of performance test results and notification of compliance reports for both area and major sources. Implementation of the rules is expected to reduce HAP metal emissions from primary copper smelters, improve human health, and reduce environmental impacts associated with those emissions. This final action will also result in improved monitoring, compliance, and implementation of the existing standards.

During development of these proposed and final rules, the EPA also completed a demographic analysis which indicates that cancer risks associated with emissions from the major source category disproportionately affect communities with environmental justice concerns, including low-income residents, American Indians, and Hispanics living near these facilities. Once the new and revised standards (described in this preamble) are implemented, risks in nearby communities due to HAP emissions will be reduced to acceptable levels and the NESHAP will provide an ample margin of safety to protect public health.

B. Does this action apply to me?

The source categories that are the subject of this action are Primary Copper Smelting Major Sources regulated under 40 CFR part 63, subpart QQQ, and Primary Copper Smelting Area Sources, regulated under 40 CFR part 63, subpart EEEEEE. The North American Industry Classification System (NAICS) code for the primary copper smelting industry is 331410. This list of categories and NAICS codes is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that this final action is likely to affect. The final standards will be directly applicable to the affected sources. State, local, and Tribal governments would not be directly affected by this final action. As defined in the *Initial List of Categories of Sources Under Section 112(c)(1) of the Clean Air Act Amendments of 1990* (see 57 FR 31576, July 16, 1992) and *Documentation for Developing the Initial Source Category List, Final Report* (see EPA–450/3–91–030, July 1992), the Primary Copper Smelting major source category addresses any major source facility engaged in the pyrometallurgical process used for the extraction of copper from sulfur oxides, native ore concentrates, or other copper bearing minerals. As originally defined, the category includes, but is not limited to, the following smelting process units: roasters, smelting furnaces, and converters. Affected sources under the current major source NESHAP are concentrate dryers, smelting furnaces, slag cleaning vessels, converters, and fugitive emission sources. The area source category was added to the source category list in 2002 (67 FR 70427, 70428). Affected sources under the area source NESHAP are concentrate dryers, smelting vessels (*e.g.*, furnaces), converting vessels, matte drying and grinding plants, secondary gas systems, and anode refining operations.

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this final action will also be available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this final action at *https://www.epa.gov/stationary-sources-air-pollution/primary-copper-smelting-national-emissions-standards-hazardous-air* and at *https://www.epa.gov/stationary-sources-air-pollution/primary-copper-smelting-area-sources-national-emissions-standards*. Following publication in the **Federal Register**, the EPA will post the **Federal Register** version and key technical documents at this same website.

Additional information is available on the RTR website at *https://www.epa.gov/stationary-sources-air-pollution/risk-and-technology-review-national-emissions-standards-hazardous*. This information includes an overview of the RTR program and links to project websites for the RTR source categories.

D. Judicial Review and Administrative Reconsideration

Under Clean Air Act (CAA) section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit (the Court) by July 12, 2024. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. This section also provides a mechanism for the EPA to reconsider the rule if the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within the period for public comment or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule. Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, WJC South Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Background

A. What is the statutory authority for this action?

Section 112 of the CAA establishes a two-stage regulatory process to address emissions of HAP from stationary sources. In the first stage, we must identify categories of sources emitting one or more of the HAP listed in CAA section 112(b) and then promulgate technology-based NESHAP for those sources. ''Major sources'' are those that emit, or have the potential to emit, any single HAP at a rate of 10 tons per year (tpy) or more, or 25 tpy or more of any combination of HAP. For major sources, these standards are commonly referred to as MACT standards and must reflect the maximum degree of emission reductions of HAP achievable (after considering cost, energy requirements, and non-air quality health and environmental impacts). In developing MACT standards, CAA section 112(d)(2) directs the EPA to consider the application of measures, processes, methods, systems, or techniques, including, but not limited to, those that reduce the volume of or eliminate HAP emissions through process changes, substitution of materials, or other modifications; enclose systems or processes to eliminate emissions; collect, capture, or treat HAP when released from a process, stack, storage, or fugitive emissions point; are design, equipment, work practice, or operational standards; or any combination of the above.

For these MACT standards, the statute specifies certain minimum stringency requirements, which are referred to as MACT floor requirements, and which may not be based on cost considerations. See CAA section 112(d)(3). For new sources, the MACT floor cannot be less stringent than the emission control achieved in practice by the best-controlled similar source. The MACT standards for existing sources can be less stringent than floors for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources). In developing MACT standards, we must also consider control options that are more stringent than the floor under CAA section 112(d)(2). We may establish standards more stringent than the floor, based on the consideration of the cost of achieving the emissions reductions, any non-air quality health and environmental impacts, and energy requirements. Standards more stringent than the floor are commonly referred to as beyond-the-floor (BTF) standards. In certain instances, as provided in CAA section 112(h), the EPA may set work practice standards in lieu of numerical emission standards. For area sources, CAA section 112(d)(5) gives the EPA discretion to set standards based on generally available control technologies or management practices (Generally Available Control Technology (GACT) standards) in lieu of MACT standards.

In the second stage of the regulatory process, the CAA requires the EPA to undertake two different analyses, which we refer to as the technology review and the residual risk review. Under the technology review, we must review the technology-based standards and revise them ''as necessary (taking into account developments in practices, processes, and control technologies)'' no less frequently than every 8 years, pursuant to CAA section 112(d)(6). In conducting this review, the EPA is not required to recalculate the MACT floors that were established in earlier rulemakings. *Natural Resources Defense Council (NRDC)* v. *EPA*, 529 F.3d 1077, 1084 (D.C. Cir. 2008). *Association of Battery Recyclers, Inc.* v. *EPA*, 716 F.3d 667 (D.C. Cir. 2013). The EPA may consider cost in deciding whether to revise the standards pursuant to CAA section 112(d)(6). The EPA is required to address regulatory gaps, such as missing standards for listed air toxics known to be emitted from the source category, and any new MACT standards must be established under CAA sections 112(d)(2) and (3), or, in specific circumstances, CAA sections 112(d)(4) or (h). *Louisiana Environmental Action Network (LEAN)* v. *EPA*, 955 F.3d 1088 (D.C. Cir. 2020). Under the residual risk review, we must evaluate the risk to public health remaining after application of the technology-based standards and revise the standards, if necessary, to provide an ample margin of safety to protect public health or to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect. The residual risk review is required within 8 years after promulgation of the technology-based standards, pursuant to CAA section 112(f). In conducting the residual risk review, if the EPA determines that the current standards provide an ample margin of safety to protect public health, it is not necessary to revise the MACT standards pursuant to CAA section 112(f).[1] Section 112(d)(5) of the CAA provides that this residual risk review is not required for categories of area sources subject to GACT standards. For more information on the statutory authority for this rule, see 87 FR 1616 and 88 FR 47415.

B. What is the Primary Copper Smelting source category and how does the NESHAP regulate HAP emissions from the source category?

The primary copper smelting source category includes any facility that uses a pyrometallurgical process to produce anode copper from copper ore concentrates. Primary copper smelting begins with copper mines supplying the ore concentrate (typically 30 percent copper). In most cases, the moisture is reduced from the ore concentrate in dryers, and then the ore concentrate is fed through a smelting furnace where it is melted and reacts to produce copper matte. One existing smelter is able to feed its copper concentrate directly to the smelting furnace without prior drying. Copper matte is a molten solution of copper sulfide mixed with iron sulfide and is about 60 percent copper. The solution is further refined using converters to make blister copper, which is approximately 98 percent copper. Converters use oxidation to remove sulfide as sulfur dioxide (SO_2) gas and the iron as a ferrous oxide slag. The majority of the SO_2 gases are sent to a sulfuric acid plant. The slag is removed, cooled, and often processed again to remove any residual copper. The blister copper is reduced in the anode furnace to remove impurities and oxygen, typically by injecting natural gas and steam, to produce a high purity

---

[1] The Court has affirmed this approach of implementing CAA section 112(f)(2)(A): *NRDC* v. *EPA*, 529 F.3d 1077, 1083 (D.C. Cir. 2008) (''If EPA determines that the existing technology-based standards provide an 'ample margin of safety,' then the Agency is free to readopt those standards during the residual risk rulemaking.'').

copper. The molten copper from the anode refining furnace is poured into molds and cooled to produce solid copper ingots called anodes. This process is known as casting. The anodes are sent to a copper refinery, either on-site or at an off-site location, for further purification using an electrolytic process to obtain high purity copper that is sold as a product.

The processing units of interest at primary copper smelters, because of their potential to generate HAP emissions, are the following: dryers, smelting furnaces, copper converters, anode refining furnaces, and, if present, copper holding vessels, slag cleaning vessels, and matte drying and grinding plants. In addition, fugitive emissions are sources of HAP at primary copper smelters. The transfer of matte, converter slag, and blister copper is the primary source of fugitive emissions.

There are three primary copper smelting facilities in the U.S. that are subject to the NESHAPs in this review. Two of the facilities, Asarco and Freeport (also referred to as FMMI), are both located in Arizona and are major sources of HAP emissions that are subject to subpart QQQ, the major source NESHAP. The third facility, Kennecott, is located in Utah and is an area source subject to subpart EEEEEE, the area source NESHAP.

Two of the facilities (Asarco and Kennecott) use flash smelting furnaces (the INCO smelting furnace and the Outotec®, respectively). Flash smelting furnaces consist of blowing fine, dried copper sulfide concentrate and silica flux with air, oxygen-enriched air or oxygen into a hot hearth-type furnace. The sulfide minerals in the concentrate react with oxygen resulting in oxidation of the iron and sulfur, which produces heat and therefore melting of the solids. The molten matte and slag are removed separately from the furnace as they accumulate, and at the facility using the INCO furnace, the matte is transferred via ladles to the copper converters. The Freeport facility uses an ISASMELT furnace. The ISASMELT process involves dropping wet feed through a feed port, such that dryers are not needed. A mixture of air, oxygen, and natural gas is blown through a vertical lance in the center of the furnace, generating heat and melting the feed. The molten metal is then tapped from the bottom and sent to an electric furnace to separate the matte from slag. The slag is removed from the electric furnace through tapholes and is transferred to slag pots via ladles. The matte is also removed from the electric furnace through tapholes and transferred to the converter via ladles.

At the area source primary copper smelter, molten copper matte tapped from the Outotec® smelting furnace is not transferred as molten material directly to the converting vessel as is performed at the two major source smelters. Instead, the matte is first quenched with water to form solid granules of copper matte. These matte granules are then ground to a finer texture and fed to the flash converting furnace for the continuous converting of copper. The continuous copper converter differs significantly in design and operation from the cylindrical batch converters operated at the other U.S. smelters. Because there are no transfers of molten material between the smelting furnace and the continuous copper converter, this technology has inherently lower potential HAP emissions than a smelter using batch copper converting technology.

In either a facility using batch copper converting or a facility using continuous copper converting, and as discussed above in this section, molten blister copper is next transferred from the converting vessel to an anode furnace for refining to further remove residual impurities and oxygen, and then poured into molds to produce solid copper ingots called anodes. The anode copper is sent to a copper refinery, either on-site or at another location, where it is further purified using an electrolytic process to obtain the high purity copper that is sold as a product. The copper refinery is not part of the primary copper smelting source category.

The current NESHAP for major sources (40 CFR part 63, subpart QQQ) was proposed on April 20, 1998 (63 FR 19582), with a supplement to the proposed rule published on June 26, 2000 (65 FR 39326). The final rule, promulgated on June 12, 2002 (67 FR 40478), established PM standards as a surrogate for HAP metals for copper concentrate dryers, smelting furnaces, slag cleaning vessels, and existing converters. The major source NESHAP applies to major sources that use batch copper converters. Regarding new sources, the NESHAP prohibits batch converters for new sources, which indirectly means that any new source would need to have continuous converters, similar to the area source (Kennecott), or another technology. The converter building is subject to an opacity limit that only applies during performance testing. A fugitive dust plan is required to minimize fugitive dust emissions. Subpart QQQ also establishes requirements to demonstrate initial and continuous compliance with all applicable emission limitations, work practice standards, and operation and maintenance requirements. Annual performance testing is required to demonstrate compliance.

The NESHAP for area sources (40 CFR part 63, subpart EEEEEE) establishes GACT standards for primary copper smelting area sources and was proposed on October 6, 2006 (71 FR 59302) and finalized on January 23, 2007 (72 FR 2930). Technical corrections were then published on July 3, 2007, via direct final rule (72 FR 36363). The affected sources (*i.e.,* copper concentrate dryers, smelting vessels, converting vessels, matte drying and grinding plants, secondary gas systems and anode refining departments) are subject to PM limits as a surrogate for HAP metals. Compliance is demonstrated by either continuously measuring PM, conducting a performance test every 2.5 years, or operating a PM continuous emission monitoring system (CEMS).

C. What changes did we propose for the Primary Copper Smelting source category in our January 11, 2022, proposal and in our July 24, 2023, supplemental proposal?

On January 11, 2022, the EPA published a proposed rule in the **Federal Register** (87 FR 1616) for the NESHAP for Primary Copper Smelting, 40 CFR part 63, subpart QQQ, that took into consideration the RTR analyses and for the NESHAP for Primary Copper Smelting Area Sources, 40 CF part 63, subpart EEEEEE, that took into consideration the technology review. In the 2022 proposed rule, we proposed:

- PM limits based on the MACT floor for anode refining point sources at new and existing major sources;
- PM limits based on the MACT floor for process fugitive emissions from roofline vents of smelting furnaces at new and existing major sources;
- PM limits based on the MACT floor for process fugitive emissions from roofline vents of converters at new and existing major sources;
- PM limits based on beyond-the-floor (BTF) for process fugitive emissions from roofline vents at anode refining operations at new and existing major sources;
- PM limits based on the MACT floor for new converters at major sources;
- Facility-wide mercury limit based on BTF for any combination of stacks or other vents from the copper concentrate dryers, copper converter department, the anode refining department, and the smelting vessels at existing major sources;
- Facility-wide mercury limit based on the MACT floor for new major sources;

- Revisions to the existing fugitive dust control work practice standards to make them more robust than what is currently required by the major source NESHAP;
- Removal of SSM exemptions and associated provisions and specify that emissions standards apply at all times for both area sources and major sources; and
- Requirements for electronic reporting of performance test reports and notification of compliance reports for both area sources and major sources.

During the comment period for the 2022 proposal, the EPA received public comments from industry, Tribal nations, environmental groups, Arizona Department of Environmental Quality (ADEQ), and private citizens. After reviewing the comments, and after consideration of additional data and information received since the 2022 proposal, the EPA determined it was appropriate to gather additional data, revise some of the analyses associated with that proposal, and to publish a supplemental proposal for the major source NESHAP.

In support of the supplemental proposal, the EPA sent a section 114 information request to the Freeport facility only, as the Asarco facility has been idled since October 2019. The section 114 information request was delivered to the Freeport facility on August 31, 2022. In response to this section 114 information request, the EPA received performance test results for the Freeport facility containing emission rates of benzene, 1,4-dichlorobenzene, chlorine, formaldehyde, hexane, hydrogen fluoride, hydrogen chloride, toluene, total hydrocarbons, PAH including naphthalene, and dioxins and furans. The section 114 information request response from Freeport also provided data regarding costs and feasibility of installing additional controls for the aisle scrubber including a wet electrostatic precipitator (WESP) and a baghouse to control emissions from the Hoboken converter process fugitive capture system. Finally, the section 114 information request response from Freeport provided detailed information for input materials, emission sources, and process information.

In addition to the information collected through the section 114 information request, the EPA also received information during and after the public comment period of the 2022 proposed RTR. This additional information included cost estimates for the control devices which we expect would be needed to comply with the emission limits proposed in the 2022 proposal (*e.g.*, for mercury, lead and arsenic). It also included additional performance testing results for the roofline vents, vent fume stack, aisle scrubber, and acid plant stack. Finally, Freeport also voluntarily performed an additional performance test for mercury in 2022 and submitted those results to the EPA.

Based on evaluation of all the data, we proposed several revised and new MACT standards in a supplemental proposal published in the **Federal Register** (88 FR 47415) on July 24, 2023, pursuant to CAA sections 112(d)(2), (d)(3), (d)(6), and (f). For the supplemental proposal, which addressed only the major source NESHAP, we proposed:

- Benzene, toluene, HCl, chlorine, PAH, naphthalene and D/F limits based on the MACT floor for any new and existing combination of stacks or other vents from the copper concentrate dryers, copper converter department, the anode refining department, and the smelting vessels at major sources based on test data submitted by the only operating major source;
- Revisions to the proposed PM limits for process fugitive emissions from roofline vents of smelting vessels, converters, and anode refining operations at new and existing sources to provide a combined emission limit for all roofline vents based on additional test data and comments submitted by affected facilities;
- Revisions to the proposed mercury limits for any new and existing combination of stacks or other vents from the copper concentrate dryers, converting department, the anode refining department, and the smelting vessels to provide a limit based on the MACT floor after considering additional test data and comments submitted by affected facilities; and
- Prohibition of the use of bypass stacks for major sources.

We also co-proposed two options for further controlling HAP metals at the aisle scrubber source at Freeport as follows:

- Option 1—PM limits based on the addition of a WESP downstream of the aisle scrubber to provide additional control of the combined emissions stream from the secondary capture system for the converter department[2] and the anode refining department (*i.e.*, the same option evaluated by the EPA in the ample margin of safety analysis included in the January 2022 proposal);
- Option 2—PM limits based on the addition of a baghouse upstream of the aisle scrubber to provide additional control of the secondary capture system for the converter department.

III. What is included in this final rule?

This action finalizes the EPA's determinations pursuant to the RTR provisions of CAA section 112 for the Primary Copper Smelting major source category and amends the Primary Copper Smelting major source NESHAP, 40 CFR part 63, subpart QQQ, based on those determinations. The changes being finalized for the major sources in this action include promulgation of MACT floor-based PM limits for the anode refining department point source emissions; BTF PM limits to address process fugitive emissions from the smelting vessels, copper converter department, and anode refining roofline vents combined; MACT floor-based PM limits for new copper converter departments; MACT floor-based emission standards for previously unregulated HAP (*e.g.*, mercury, benzene, toluene, HCl, chlorine, PAH, naphthalene and D/F); and PM limits for the combined anode refining department and Hoboken converter process fugitive capture systems. This action also finalizes design standards to limit HAP metals and a BTF lead emissions limit to minimize process fugitive emissions from roofline vents for certain processes. In addition, this action finalizes work practice standards for the use of bypass stacks and revisions to the fugitive dust control plan requirements. This action also finalizes other changes to the major source NESHAP including electronic reporting requirements and the removal of SSM exemptions. This final action includes several changes to the proposed requirements in the 2022 proposal and 2023 supplemental proposal based on consideration of comments and information received during the public comment periods as described in section IV. of this preamble.

This action also finalizes the EPA's determination pursuant to the technology review provisions of CAA section 112 for the Primary Copper Smelting area source category. We determined that there are no developments in practices, processes, and control technologies that warrant revisions to the NESHAP for Primary Copper Smelting Area Sources, 40 CFR part 63, subpart EEEEEE, pursuant to CAA section 112(d)(6). However, this action finalizes amendments to the area

---

[2] Based on comments on the supplemental proposal, this system should be referred to as a process fugitive capture system for the Hoboken converters; we are clarifying this terminology in the final rule.

source NESHAP to remove SSM exemptions and associated provisions and provide electronic reporting requirements.

A. What are the final rule amendments based on the risk review for the Primary Copper Smelting source category?

This section introduces the final amendments to the Primary Copper Smelting NESHAP, 40 CFR part 63, subpart QQQ, being promulgated pursuant to CAA section 112(f). The EPA is promulgating a PM emission limit (as a surrogate for HAP metals other than mercury) of 6.3 pounds per hour (lb/hour) for process fugitive emissions from roofline vents of the smelting vessels, copper converter departments, slag cleaning vessels and anode refining departments combined, at new and existing sources. This emission limit is the same as proposed in the 2023 supplemental proposal. This combined PM emission limit for process fugitive emissions from roofline vents is also being promulgated under CAA section 112(d)(2) and (d)(3) as described in section III.C. of this preamble.

B. What are the final rule amendments based on the technology review for the Primary Copper Smelting source category?

We determined that there are developments in practices, processes, and control technologies that warrant revisions to the MACT standards for this source category. Therefore, to satisfy the requirements of CAA section 112(d)(6), we are revising the MACT standards to include a combined emission standard for the anode refining department point source emissions and Hoboken converter process fugitive capture system of 4.1 milligrams per dry standard cubic meter (mg/dscm). The promulgated standard was co-proposed in the 2023 supplemental proposal as one of the two options expected to require additional controls of the combined emission streams. The promulgated standard is expected to require the installation of PM controls (such as a baghouse) to control the emissions from the Hoboken converter process fugitive capture system before this emission stream combines with the anode refining department point source exhaust in the aisle scrubber.

We are also promulgating, as proposed in the 2022 proposal, amendments to the existing requirements for facilities to develop and implement a fugitive dust control plan pursuant to CAA section 112(d)(6) as part of technology review.

In addition, the EPA is promulgating a lead emission limit of 0.326 lb/hour under CAA section 112(d)(2) and (3) and design standards under CAA section 112(d)(6) for minimizing process fugitive emissions from any combination of roofline vents associated with the Peirce-Smith copper converter department, Inco flash furnace and the anode refining department, at new and existing sources. The design standards are being promulgated for the flash furnace area capture system, fuming ladle capture system, and the anode furnace secondary hood capture and control system to further reduce process fugitive HAP metals at facilities with a combination of the Peirce-Smith copper converter department, Inco flash furnace and the anode refining department. We note that the combined lead emission limit for reducing process fugitive emissions from roofline vents is being promulgated under CAA section 112(d)(2) and (d)(3) as described in section III.C. of this preamble. However, the design standards are being promulgated under CAA section 112(d)(6).

As part of the technology review for the major source NESHAP, we also identified regulatory gaps (previously unregulated processes or pollutants) and are establishing new standards to fill those gaps as described in section III.C. of this preamble.

C. What are the final rule amendments pursuant to CAA sections 112(d)(2) and (3) for the Primary Copper Smelting source category?

Pursuant to CAA sections 112(d)(2) and (3), we are promulgating MACT floor limits for emissions of PM (as a surrogate for HAP metals other than mercury) from new and existing anode refining departments and new copper converter departments, which were previously unregulated sources of HAP metals. We are also promulgating, pursuant to CAA sections 112(d)(2) and (3), a BTF limit for emissions of PM (as a surrogate for HAP metals other than mercury) from new and existing sources of process fugitive emissions from the roofline vents from the smelting vessels, slag cleaning vessels, the copper converter department, and the anode refining department combined, which were previously unregulated sources of HAP metals. As described in section III.A. of this preamble, the emissions standard for new and existing sources of process fugitive gases from the roofline vents from the smelting vessels, slag cleaning vessels, the converter department, and the anode refining department is also being finalized pursuant to CAA section 112(f)(2) to address the source category unacceptable risk determination. In addition, we are also promulgating, pursuant to CAA sections 112(d)(2) and (3), a BTF lead emission limit to minimize process fugitive emissions from any combination of roofline vents associated with the Peirce-Smith copper converter department, Inco flash furnace and the anode refining department. Lastly, we are promulgating, pursuant to CAA sections 112(d)(2) and (3), MACT emission limits for mercury, benzene, toluene, HCl, chlorine, PAH excluding naphthalene, naphthalene, and D/F, all of which were previously unregulated HAP. A summary of the MACT standards promulgated pursuant to CAA sections 112(d)(2) and (3) is provided in table 1 below. For more information on these standards, including their rationale, see section IV.C. of this preamble.

BILLING CODE 6560–50–P

Table 1. Summary of Final MACT Standards Pursuant to CAA Sections 112(d)(2) and (3)

HAP	Source	Promulgated Standard[1]
PM	New and existing Anode Refining Department	5.8 mg/dscm
PM	New Copper Converter Department	0.031 lb/ton copper concentrate feed charged to the smelting vessel
PM	New and existing process fugitive gases from the roofline vents from the smelting vessels, slag cleaning vessels, the copper converter department, and the anode refining department	6.3 lb/hr [2]
Lead	Existing process fugitive emissions from any combination of roofline vents associated with the Peirce-Smith copper converter department, Inco flash furnace and the anode refining department	0.326 lb/hr [2]
Mercury	New combination of stacks or other vents from the copper concentrate dryers, copper converter department, the anode refining department, slag cleaning vessels and the smelting vessels	0.00097 lb/hr
Mercury	Existing combination of stacks or other vents from the copper concentrate dryers, copper converter department, the anode refining department, slag cleaning vessels and the smelting vessels	0.033 lb/hr
Benzene	New and existing combination of stacks or other vents from the copper concentrate dryers, copper converter department, the anode refining department, slag cleaning vessels and the smelting vessels	1.7E-03 lb/ton copper concentrate feed charged to the smelting vessel
Toluene	New and existing combination of stacks or other vents from the copper concentrate dryers, copper converter department, the anode refining department, slag cleaning vessels and the smelting vessels	8.4E-04 lb/ton copper concentrate feed charged to the smelting vessel
HCl	New and existing combination of stacks or other vents from the copper concentrate dryers, copper converter department, the anode refining department, slag cleaning vessels and the smelting vessels	1.5E-03 lb/ton copper concentrate feed charged to the smelting vessel
Chlorine	New and existing combination of stacks or other vents from the copper concentrate dryers, copper converter department, the anode refining department, slag cleaning vessels and the smelting vessels	5.4E-03 lb/ton copper concentrate feed charged to the smelting vessel
PAH (excluding Naphthalene)	New and existing combination of stacks or other vents from the copper concentrate dryers, copper converter department, the anode refining department, slag cleaning vessels and the smelting vessels	1.0E-04 lb/ton copper concentrate feed charged to the smelting vessel

Naphthalene	New and existing combination of stacks or other vents from the copper concentrate dryers, copper converter department, the anode refining department, slag cleaning vessels and the smelting vessels	2.8E-04 lb/ton copper concentrate feed charged to the smelting vessel
D/F	New and existing combination of stacks or other vents from the copper concentrate dryers, converter department, the anode refining department, slag cleaning vessels and the smelting vessels	60 ng TEQ/Mg copper concentrate feed charged to the smelting vessel

[1] We are also finalizing an additional PM emission limit pursuant to CAA section 112(d)(6) technology review; see section III.B. for details.

[2] Denotes BTF emission standard.

BILLING CODE 6560–50–C

D. What are the final rule amendments addressing emissions during periods of startup, shutdown, and malfunction?

We are finalizing the elimination of SSM exemptions and associated provisions in the Primary Copper Smelting NESHAPs (40 CFR part 63, subparts QQQ and EEEEEE) as proposed in the 2022 proposal, other than clarifications and other non-substantive updates in SSM exemption removal explanation and provisions. In its 2008 decision in *Sierra Club* v. *EPA*, 551 F.3d 1019 (D.C. Cir. 2008), the court vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. Specifically, the court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and (h)(1), holding that under section 302(k) of the CAA, emissions standards or limitations must be continuous in nature and that the SSM exemption violates the CAA's requirement that some section 112 standards apply continuously. Consistent with *Sierra Club* v. *EPA*, the EPA is establishing standards in these rules that apply at all times. We have revised table 1 (the General Provisions Applicability Table) in both rules in several respects related to SSM. For example, we have eliminated the incorporation of the General Provisions requirement that the sources develop an SSM plan, changed several references related to requirements that apply during periods of SSM, and eliminated or revised certain recordkeeping and reporting requirements related to the eliminated SSM exemption. The EPA also made changes to the rules to remove or modify inappropriate, unnecessary, or redundant language in the absence of the SSM exemption. See the 2022 proposed rule for additional information on removal of SSM exemptions. In addition, for 40 CFR part 63, subpart QQQ, we are finalizing a work practice standard allowing the venting of process gases through a bypass stack during planned maintenance events under limited conditions as described in section IV.D.

E. What other changes have been made to the NESHAP?

1. Electronic Reporting

To increase the ease and efficiency of data submittal and data accessibility, the EPA is finalizing, as proposed in the 2022 proposal, a requirement that owners and operators of sources subject to the Primary Copper Smelting NESHAP for major sources (subpart QQQ) submit electronic copies of required performance test reports and performance evaluations of continuous monitoring systems (CMS) measuring relative accuracy test audit (RATA) pollutants (being finalized at 40 CFR 63.1455) through the EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). A description of the electronic data submission process is provided in the memorandum Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules, available in the docket for this action (Docket ID No. EPA–HQ–OAR–2020–0430–0031). The final rule requires that performance test results or performance evaluation of CMS measuring RATA pollutants collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the ERT website[3] at the time of the test be submitted in the format generated through the use of the ERT; or alternatively, owners or operators may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Other performance tests or performance evaluations of CMS measuring RATA pollutants collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. The final rule also requires that notification of compliance reports be submitted as a portable document format (PDF) upload in CEDRI.

We are finalizing the electronic reporting requirements for the Primary Copper Smelting NESHAP for area sources (40 CFR part 63, subpart EEEEEE) as proposed in the 2022 proposal. The electronic reporting requirements are in 40 CFR 63.11147, 63.11148, and 63.11149 of the rule, and include electronic reporting requirements for monthly emissions reports, emergency notifications, notifications of a deviation, semi-annual monitoring reports; and performance tests, where applicable.

2. Other Changes

The EPA is finalizing, as proposed in the 2022 proposal, the revision to the applicability description under § 63.1441 to clarify that the NESHAP applies to major source smelting facilities that use any type of converter, not just batch converters because the current definition limits applicability to only major sources that use batch converters. The major source NESHAP should apply to any Primary Copper major source regardless of what type of converter they use. Therefore, we are finalizing this change.

Regarding revisions to testing requirements, the Agency is finalizing, as proposed in the 2022 proposal,

---

[3] *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

revisions to the wording in § 63.1450 clarifying that facilities must test for filterable particulate, not total particulate. The test methods in § 63.1450(a) have not changed for PM from the existing regulation. The methods in the existing regulation (Methods 5, 5D, and 17) are methods for filterable PM. Total PM includes filterable PM and condensable PM. The condensable PM test method (Method 202) is not included in the existing regulation for the emission standards set in 2002. In conjunction with clarifying that facilities must test for filterable particulate, not total particulate, we are changing all instances of the wording ''total particulate matter'' in the current rule to ''filterable particulate matter.''

The Agency is finalizing, as proposed in the 2022 proposal and 2023 supplemental proposal, the addition of appropriate test methods for PM_{10}, fugitive PM, mercury, benzene, toluene, chlorine, hydrogen chloride, PAH excluding naphthalene, naphthalene, and dioxins/furans, as well as updating test methods that are incorporated by reference because the affected facilities will need to know what test methods they need to use to demonstrate compliance with the new standards.

Finally, the EPA is finalizing, as proposed in the 2022 proposal, to revise the definitions under § 63.1459 by changing the term ''smelting furnace'' to ''smelting vessel'' to be consistent with the definition in the area source rule, 40 CFR part 63, subpart EEEEEE, because we find it is appropriate that both rules include the broader definition of smelting vessel, which is already in the area source rule. The specific definition is as follows: Smelting vessel means a furnace, reactor, or other type of vessel in which copper ore concentrate and fluxes are smelted to form a molten mass of material containing copper matte and slag. Other copper-bearing materials may also be charged to the smelting vessel.

F. What are the effective and compliance dates of the standards?

For the additional MACT floor emission limits (mercury, HCl, chlorine, D/F, benzene, toluene, PAHs excluding naphthalene, and naphthalene) in 40 CFR part 63, subpart QQQ, the EPA is finalizing, as proposed in the 2023 supplemental proposal, the requirement that existing facilities must comply with these limits within 1 year after promulgation because we estimated both facilities can meet these MACT floor limits without having to install new controls. Similarly, for the new PM emission standard for anode refining point sources where the anode emissions are not combined with Hoboken converter process fugitive capture system emissions in an aisle scrubber, the Agency is finalizing, as proposed in the 2022 proposal, the proposed requirement that existing facilities must comply within 1 year after promulgation of the final rule as major source facilities that do not combine their anode point source emissions are expected to meet the limit without additional controls. For anode refining point sources that combine their anode emissions with Hoboken converter process fugitive capture system emissions in an aisle scrubber, compliance with the anode refining point source limit will be demonstrated through compliance with the combined PM limit at the aisle scrubber outlet and its associated compliance date.

For the combined PM limit at the aisle scrubber outlet, which treats combined emissions from the Hoboken converter process fugitive capture system and anode refining point source, the EPA is finalizing that facilities must comply with this limit within 3 years after promulgation of the final rule. We are allowing up to 3 years to meet this limit as we expect facilities will need up to 3 years to design, construct and operate the necessary capture and control equipment to meet the limit.

For the combined process fugitive PM roofline emissions limit for copper converter departments, anode refining departments, slag cleaning vessels and smelting vessel roofline vents, the EPA is finalizing, as proposed in the 2023 supplemental proposal, the requirement that existing facilities comply with this limit within 2 years after promulgation of the final rule. We are allowing up to two years to meet this limit as we expect facilities will need up to 2 years to design, construct and operate the necessary capture and control equipment to meet the limit.

For the combined process fugitive lead roofline emissions limit for Peirce-Smith copper converter department, Inco flash furnace and the anode refining department roofline vents, the EPA is finalizing that facilities must comply with this limit within 3 years after promulgation of the final rule. We are allowing up to 3 years to meet this limit as we expect facilities will need up to 3 years to design, construct and operate the necessary capture and control equipment to meet the limit.

For all other changes in this action we are finalizing, as proposed, that existing facilities must comply within 180 days after promulgation of the final rule.

New sources must comply with all of the standards immediately upon the effective date of the standard, May 13, 2024, or upon startup, whichever is later.

We are also finalizing amendments to §§ 63.1442 and 63.1443 and adding a new table (table 4 to 40 CFR part 63, subpart QQQ) which provides the applicability dates for previously unregulated affected sources (*e.g.*, anode refining department, bypass stack), as well as the effective dates and compliance dates for the emission standards proposed in the 2022 proposal and 2023 supplemental proposal which are being promulgated in this final action.

IV. What is the rationale for our final decisions and amendments for the Primary Copper Smelting source category?

For each issue, this section provides a description of what we proposed and what we are finalizing for the issue, the EPA's rationale for the final decisions and amendments, and a summary of key comments and responses. For all comments not discussed in this preamble, comment summaries and the EPA's responses can be found in the National Emission Standards for Hazardous Air Pollutant Emissions: Primary Copper Smelting Residual Risk and Technology Review and Primary Copper Smelting Area Source Technology Review: Summary of Public Comments and Responses document, available in the docket for this action (Docket ID No. EPA–HQ–OAR–2020–0430).

A. Residual Risk Review for the Primary Copper Smelting Source Category

1. What did we propose pursuant to CAA section 112(f) for the Primary Copper Smelting source category?

Pursuant to CAA section 112(f), the EPA conducted a residual risk review and presented the results of this review, along with the proposed decisions regarding risk acceptability and ample margin of safety, in the January 11, 2022, proposed rule (87 FR 1616). In the 2022 proposed rule, the EPA determined that risks from the primary copper smelting source category were unacceptable due to HAP metal (primarily lead and arsenic) emissions. Based on new information and data received after the 2022 proposal through the comment period and issuance of a 2022 CAA section 114 information request from the Freeport facility, the EPA updated the baseline risk assessment, updated control Option 1, and added a new control Option 2 that affected the Freeport facility only. The Asarco facility has been idle since October 2019, and therefore, a section

114 information request was not issued to them. The risk results for the Asarco facility did not change in the 2023 supplemental proposal because we did not receive any new data or information after the 2022 proposal was published and before the supplemental proposal was published.

The results of the risk assessment for the 2022 proposal are described in more detail in the Residual Risk Assessment for the Primary Copper Smelting Major Source Category in Support of the 2021 Risk and Technology Review Proposed Rule document, which is available in the docket (Docket ID No. EPA–HQ–OAR–2020–0430–0051). The results of the baseline risk assessment for the 2023 supplemental proposal are presented in table 2 and in more detail in the residual risk document, Revised Residual Risk Assessment for the Freeport Smelter (Miami, AZ) in Support of the 2023 Supplemental Proposal for the Primary Copper Smelting Source Category, which is available in the Docket for this action (Docket ID No. EPA–HQ–OAR–2020–0430–0187).

Table 2. Primary Copper Smelting Major Source Category Inhalation Risk Assessment Results Supporting the Supplemental Proposal

Number of Facilities[1]	Maximum Individual Cancer Risk (in 1 million)[2]		Estimated Population at Increased Risk of Cancer ≥ 1-in-1 Million		Estimated Annual Cancer Incidence (cases per year)		Maximum Noncancer HI and 3-month Lead Concentration (ug/m^3) [3]		Maximum Screening Acute Noncancer HQ [4]
	Actual Emissions	Allowable Emissions	Actual Emissions	Allowable Emissions	Actual Emissions	Allowable Emissions	Actual Emissions	Allowable Emissions	Actual Emissions
1	70	90	22,900	29,001	0.002	0.003	HI =1 (arsenic) developmental Pb Conc: 0.17	HI =1 (arsenic) developmental Pb Conc: 0.24	HQ (REL) = 7 (Arsenic)

[1] The Freeport facility was the only facility evaluated in this updated risk analysis.

[2] Maximum individual excess lifetime cancer and noncancer risk due to arsenic emissions from the source category, 71 percent from the anode refining roofline at Freeport and 23 percent from anode furnaces and converters point source emissions from the Aisle Scrubber at Freeport.

[3] The modeled max 3-month off-site lead concentration is compared to the lead (Pb) National Ambient Air Quality Standards (NAAQS) standard of 0.15 ug/m^3 based upon actual and allowable emissions from the source category. The Pb NAAQS standard was developed to address all exposure pathways (inhalation and ingestion).

[4] The maximum estimated off-site acute exposure concentration was divided by available short-term dose-response values to develop an array of hazard quotient (HQ) values. The HQ value shown here is based on the lowest available acute dose-response value, which is the reference exposure level (REL). There are no other acute health benchmarks for arsenic other than the 1-hour REL.

A refined modeling analysis for the 2022 proposal was conducted at the facility with the highest annual concentration of lead, Freeport, to characterize ambient concentrations of lead for 3-month intervals. The maximum 3-month concentration was predicted for each off-site receptor. The concentrations were then compared to the Pb NAAQS of 0.15 micrograms per cubic meter (ug/m3). The maximum 3-month off-site modeled concentration was 0.17 ug/m3 for actual emissions and 0.24 ug/m3 for allowable emissions, and these results occurred near the Freeport facility. These results did not change in the 2023 supplemental proposal.

The inhalation risk assessment in the 2023 supplemental proposal estimated that the baseline cancer maximum individual risk (MIR) was 70-in-1 million for the source category based on actual emissions. The total estimated cancer incidence from the source category was 0.002 excess cancer cases per year, or one excess case every 500 years, with arsenic compounds contributing 97 percent of the cancer incidence for the source category in the 2023 supplemental proposal. Approximately 22,900 people of the 46,460 people within 50 km of the facility were estimated to have cancer risks above 1-in-1 million from HAP emitted from the source category. The HEM–4 model predicted the maximum chronic noncancer hazard index (HI) value for the source category was 1 (developmental), with an acute non-cancer HQ value equal to 7 driven by emissions of arsenic from the anode refining roofline at Freeport and, to a lesser degree, the anode furnace point source and Hoboken converter process fugitive capture system emissions emitted through the aisle scrubber at Freeport.

The inhalation risk assessment based on MACT-allowable emissions did not change from the 2022 proposal and indicated that the cancer MIR was 90-in-1 million. The total estimated cancer incidence from the source category was

0.003 excess cancer cases per year, or one excess case every 333 years, with arsenic contributing 90 percent and cadmium contributing 8 percent of the cancer incidence for the source category. Approximately 29,001 people were estimated to have cancer risks above 1-in-1 million from exposure to HAP emissions if HAP were emitted at the levels allowed under the NESHAP as it existed prior to finalization of this regulatory action. The chronic non-cancer risks remained the same as actuals, with acute non-cancer hazards not being modeled due to the uncertainty of estimating acute impacts based upon hourly allowable emission estimates.

Regarding multipathway risk, we concluded in the 2022 proposal that there was no significant potential for multipathway health effects based upon EPA's Tier 3 screening analysis. Due to the conservative nature of the screens and the level of additional refinements that would go into a site-specific multipathway assessment, were one to be conducted, we are confident that the HQ for ingestion exposure, specifically cadmium and mercury through fish ingestion, is less than 1. For arsenic, maximum cancer risk posed by fish ingestion would also be reduced to levels below 1-in-1 million, and maximum cancer risk under the rural gardener scenario would decrease to 20-in-1 million or less. The estimated risks for the garden scenario seem unlikely due to the arid climate of the area and the hypothetical nature of the scenario. Further details on the Tier 3 screening assessment can be found in Appendix 10–11 of *Residual Risk Assessment for the Primary Copper Smelting Major Source Category in Support of the Risk and Technology Review 2021 Proposed Rule.*

In the 2023 supplemental proposal, we estimated that the multipathway and inhalation risk results would be reduced further due to baseline arsenic emissions at proposal (2022) being lowered based upon additional data being received. We also estimated in the 2023 supplemental proposal that, although the mercury emissions increased from the 2022 proposal baseline, the mercury HQ would still be less than 1 (0.2) for the fisher scenario.

For the 2023 supplemental proposal, the Agency weighed all the health risk factors in the risk acceptability determination and proposed that the risks from the Primary Copper Smelting source category are unacceptable at baseline. To address the unacceptable risks, in the supplemental proposal, we proposed a combined PM emission limit for process fugitive emissions from roofline vents of smelting furnaces, converters, and anode refining operations, which would significantly reduce risks. We estimated in the supplemental proposal that this combined PM limit would reduce emissions of HAP metal (primarily lead and arsenic) by 4.59 tpy. To be able to comply with the limit, we estimated that the Freeport facility would need to install controls (e.g., improved capture system, including hoods, ductwork, and fans, and one additional baghouse) to reduce process fugitive roofline emissions from the anode refining source, the main risk driver. As described in the supplemental proposal, we estimated that these controls would reduce the MIR at Freeport from 70-in-1 million to an estimated 20-in-1 million and that the acute noncancer HQ (for arsenic) would be reduced from 7 to 2 (based on actual emissions). In addition, the modeled lead concentrations would be reduced below the NAAQS. We estimated that the MIR for Asarco would remain at 60-in-1 million and would be the source category MIR after the proposed controls are applied at Freeport. In the supplemental proposal, we concluded that these risks, after implementation of proposed controls, were acceptable. We also proposed that existing facilities would need to comply within two years after promulgation of the final rule and new facilities must comply with all requirements in the final rule upon start up. We proposed that compliance would be demonstrated through an initial performance test followed by a compliance test once per year.

We then considered whether the Primary Copper Smelting NESHAP provides an ample margin of safety to protect public health and whether more stringent standards are necessary to prevent an adverse environmental effect, taking into consideration costs, energy, safety, and other relevant factors. In considering whether the standards should be tightened to provide an ample margin of safety to protect public health, we considered the same risk factors that we considered for our acceptability determination and also considered the costs, technological feasibility, and other relevant factors related to emissions control options that might reduce risks associated with emissions from the source category.

As discussed in the 2023 supplemental proposal, pursuant to CAA section 112(d)(6) and to provide an ample margin of safety to protect public health pursuant to CAA section 112(f)(2), the EPA co-proposed two regulatory options for additional control of either the secondary capture system for the converter department[4] or additional control of the combined emissions stream of the secondary capture system for the converter department and the point source emissions from the anode refining department. For Option 1, a WESP would be located downstream of the aisle scrubber and therefore further control the combined emissions stream of the secondary capture system for the converter department and the point source emissions from the anode refining department. Under Option 2, a baghouse would be installed upstream of the aisle scrubber to provide additional control of the secondary capture system for the converter department. The EPA proposed that these control options would result in more stringent emission standards for these emission sources than were currently required in 40 CFR part 63, subpart QQQ.

In the 2022 proposal, the EPA evaluated additional work practices to reduce fugitive dust emissions, and the Agency found that the implementation of a more robust fugitive dust plan would result in an unquantified reduction of HAP, and we therefore proposed this requirement in the 2022 proposal. In the 2022 proposal, the EPA proposed that the combination of the standards for anode refining roof vents, fugitive dust plan and all other current standards in the NESHAP would ensure the NESHAP provides an ample margin of safety to protect public health.

2. How did the risk review change for the Primary Copper Smelting source category?

While reviewing the information provided during the 2023 supplemental proposal public comment period and reviewing the data provided during the section 114 process, a correction was made to the spreadsheet used to calculate the average emissions from the aisle scrubber based on stack tests provided by Freeport. The correction resulted in a slightly lower average arsenic emission rate for this source (from 0.626 tpy in the supplemental proposal to 0.563 tpy in the final rule), and therefore we re-modeled the baseline and roofline vent control scenarios as well as the two control options for the aisle scrubber. In addition to the corrected emission rate for the aisle scrubber, the EPA re-evaluated the estimated control efficiencies of the control options co-

---

[4] Based on cmments on the supplement proposal, this system should be referred to as a roofline capture sysem for the Hoboken converters; we are claarifying this termionlogy in the final rule.

proposed for the aisle scrubber source at Freeport based on the comments and information received on the supplemental proposal. These comments and our responses are discussed further in section IV.A.3. of this preamble.

As discussed in the memorandum *Cost Estimates for Additional Controls of Freeport's Aisle Scrubber—REVISED*, which is available in the docket for this action, and as further discussed in section IV.B. of this preamble, we updated the control efficiency estimates for the aisle scrubber control options. In the 2023 supplemental proposal, we estimated that under Option 1, installing a WESP downstream of the aisle scrubber would achieve 95 percent control efficiency, and we estimated 6.3 tpy metal HAP reductions. Based on the comments received from Freeport regarding the technical feasibility of controlling the high-volume aisle scrubber exhaust stream using a WESP and our evaluation of those comments, we updated the estimated control efficiency for the WESP option to 73 percent, and we now estimate 4.9 tpy metal HAP reduced. In the 2023 supplemental proposal, we estimated that under Option 2 (Baghouse option), installing a baghouse upstream of the aisle scrubber to control the Hoboken converter process fugitive capture system gas stream for the copper converter department would reduce metal HAP emissions by 4.5 tpy. Note that in the supplemental proposal, we referred to the process fugitive capture system as a ''secondary'' capture system. However, Freeport commented that the capture system is better characterized as a tertiary capture system. Therefore, for the remainder of this preamble, we refer to this capture system as the Hoboken converter process fugitive capture system. Furthermore, based on comments received from Freeport in response to the 2023 supplemental proposal regarding the technical feasibility of controlling the high-volume Hoboken converter process fugitive capture system using a baghouse and our evaluation of those comments, we now estimate the baghouse will achieve 61 percent control efficiency of the Hoboken converter process fugitive capture system gas stream, and using the same assumption that this gas stream contributes 75 percent to the aisle scrubber, we estimate that HAP metals will be reduced under this option by 3.0 tpy (which represents an overall control efficiency of 46 percent for the aisle scrubber). Therefore, the modeling conducted in support of the final rule was updated to reflect these new control efficiencies. The results of the updated modeling for the aisle scrubber control options, in addition to our consideration of public comment on this issue, resulted in a change to what we proposed for ample margin of safety. The details of what we are finalizing for the ample margin of safety analysis are in section IV.A.3. of this preamble. The details of what we are promulgating for the aisle scrubber source are in section IV.B.3.

With the exception of the revised emissions described above, the risk assessment supporting the final rule was conducted in the same manner, using the same models and methods, as that conducted for the supplemental proposal. The documentation for the final rule risk assessment can be found in the memorandum titled *Freeport Baseline and Control Options Re-model Risk Analysis Memo*, which is available in the docket for this rulemaking.

Inhalation Risk Assessment Results.

Table 3 presents the updated summary of the inhalation risk assessment results based on the updated modeling supporting the final rule. The results are very similar to those of the 2023 supplemental proposal. The only changes are to the number of people at increased risk of cancer greater than or equal to 1-in-1 million.

BILLING CODE 6560–50–P

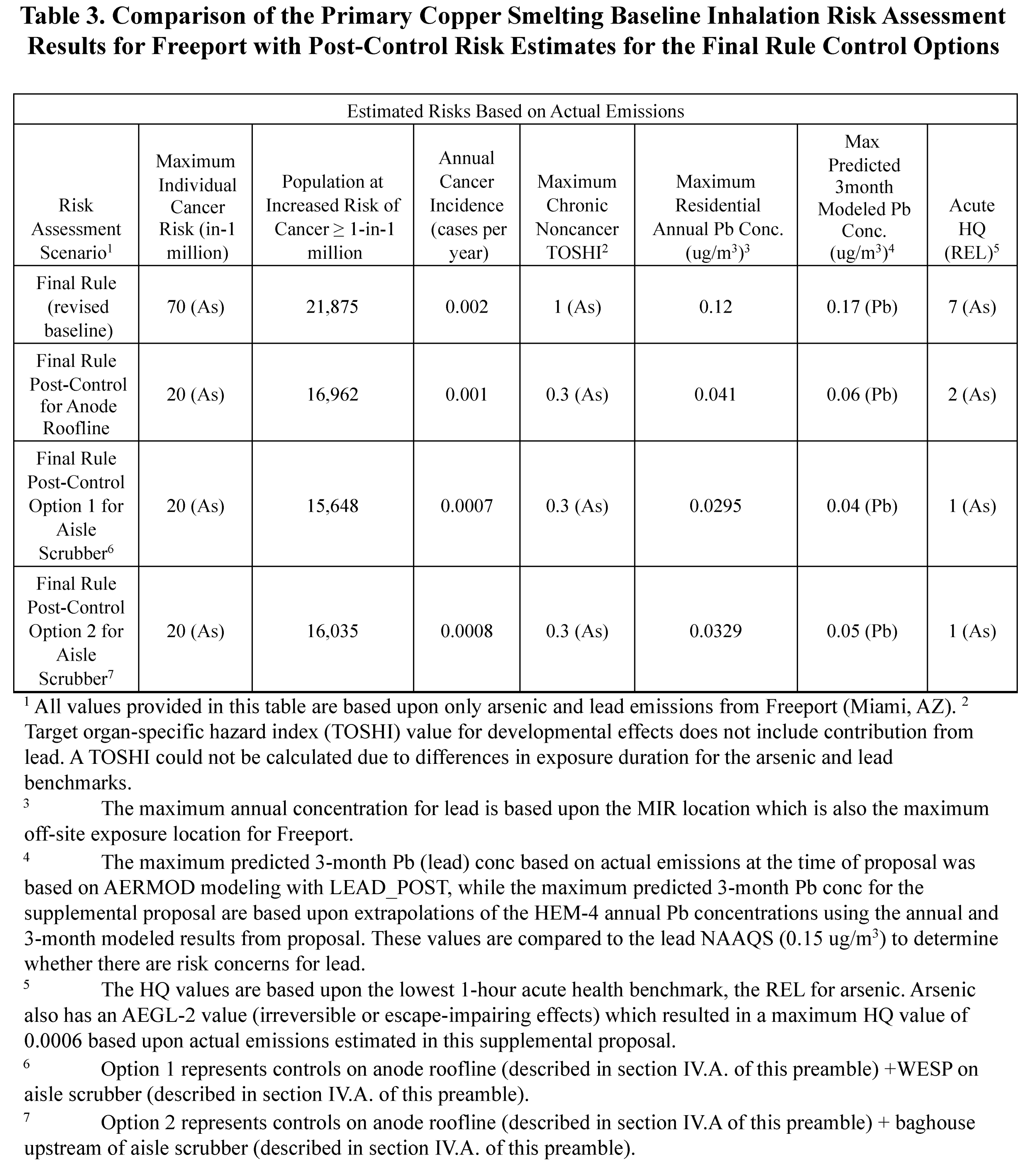


Table 3. Comparison of the Primary Copper Smelting Baseline Inhalation Risk Assessment Results for Freeport with Post-Control Risk Estimates for the Final Rule Control Options

Estimated Risks Based on Actual Emissions							
Risk Assessment Scenario[1]	Maximum Individual Cancer Risk (in-1 million)	Population at Increased Risk of Cancer ≥ 1-in-1 million	Annual Cancer Incidence (cases per year)	Maximum Chronic Noncancer TOSHI[2]	Maximum Residential Annual Pb Conc. (ug/m^3)[3]	Max Predicted 3month Modeled Pb Conc. (ug/m^3)[4]	Acute HQ (REL)[5]
Final Rule (revised baseline)	70 (As)	21,875	0.002	1 (As)	0.12	0.17 (Pb)	7 (As)
Final Rule Post-Control for Anode Roofline	20 (As)	16,962	0.001	0.3 (As)	0.041	0.06 (Pb)	2 (As)
Final Rule Post-Control Option 1 for Aisle Scrubber[6]	20 (As)	15,648	0.0007	0.3 (As)	0.0295	0.04 (Pb)	1 (As)
Final Rule Post-Control Option 2 for Aisle Scrubber[7]	20 (As)	16,035	0.0008	0.3 (As)	0.0329	0.05 (Pb)	1 (As)

[1] All values provided in this table are based upon only arsenic and lead emissions from Freeport (Miami, AZ). [2] Target organ-specific hazard index (TOSHI) value for developmental effects does not include contribution from lead. A TOSHI could not be calculated due to differences in exposure duration for the arsenic and lead benchmarks.

[3] The maximum annual concentration for lead is based upon the MIR location which is also the maximum off-site exposure location for Freeport.

[4] The maximum predicted 3-month Pb (lead) conc based on actual emissions at the time of proposal was based on AERMOD modeling with LEAD_POST, while the maximum predicted 3-month Pb conc for the supplemental proposal are based upon extrapolations of the HEM-4 annual Pb concentrations using the annual and 3-month modeled results from proposal. These values are compared to the lead NAAQS (0.15 ug/m^3) to determine whether there are risk concerns for lead.

[5] The HQ values are based upon the lowest 1-hour acute health benchmark, the REL for arsenic. Arsenic also has an AEGL-2 value (irreversible or escape-impairing effects) which resulted in a maximum HQ value of 0.0006 based upon actual emissions estimated in this supplemental proposal.

[6] Option 1 represents controls on anode roofline (described in section IV.A. of this preamble) +WESP on aisle scrubber (described in section IV.A. of this preamble).

[7] Option 2 represents controls on anode roofline (described in section IV.A of this preamble) + baghouse upstream of aisle scrubber (described in section IV.A. of this preamble).

3. What key comments did we receive on the risk review, and what are our responses?

We received comments regarding the risk assessment for the Primary Copper Smelting source category. The following is a summary of some of the more significant comments and our responses to those comments. Other comments received and our responses to those comments can be found in the document titled *National Emission Standards for Hazardous Air Pollutant Emissions: Primary Copper Smelting Residual Risk and Technology Review and Primary Copper Smelting Area Source Technology Review: Summary of Public Comments and Responses*, available in the docket for this action (Docket ID No. EPA–HQ–OAR–2020–0430).

Comment: In response to the EPA's request for comment on our ample margin of safety analysis in the 2022 proposal, in which we discussed and sought comment on but decided not to propose additional controls for the aisle scrubber, specifically a WESP, one commenter stated that they agreed with our decision. The commenter suggested that the aisle scrubber should be subject to a concentration-based filterable particulate matter (fPM) limit of 23 mg/dscm similar to other vents processing emissions from the vessels managing molten material, and that the existing MACT floor emissions from the aisle scrubber do not significantly contribute to the estimated risks from metal HAP. Other commenters supported our consideration of additional controls for the aisle scrubber. In the 2023 supplemental proposal, we discussed another ample margin of safety analysis in which we co-proposed two possible control options for the aisle scrubber, a WESP downstream of the aisle scrubber or a baghouse upstream of the aisle scrubber. One commenter expressed support for the additional controls on the aisle scrubber and for the associated reduction to risk. Several commenters stated the proposed options do not meet the requirements for ample margin of safety, which according to the commenters must be cost effective, feasible, and provide meaningful improvement in risk to public health. One of the commenters explained that the two metrics for evaluating risk reduction are based on the MIR cancer risk and the noncancer HQ. Concerning these control options, the commenters asserted the MIR is unchanged when reducing to significant digits and that it remains at 20-in-1 million after accounting for the associated reductions. One commenter noted that these MIR values consider expected reductions from other risk-based standards in the 2022 proposal and 2023 supplemental proposal (*e.g.*, the process fugitive roofline vent standard). One of the commenters took issue with the standard being applied only to the Freeport facility. The commenter contended that the roofline controls to achieve acceptable risk leave the MIR for the other major source copper smelter (Asarco) ''untouched'' at 60-in-1 million, asserting that this is ''unfair, arbitrary and capricious, and unsupported by the record.'' While the EPA estimated the HQ would drop from 2 to 1 for both options in the 2023 proposed rule, the commenter argued that the acute arsenic HQ value is based on a poorly documented and outdated study, and that more recent studies have failed to demonstrate the developmental impact which is at the foundation of the EPA's HQ assessment. The commenters added that the EPA has accepted much higher HQ values for arsenic in other rules (*e.g.*, Integrated Iron and Steel Manufacturing NESHAP 85 FR 42074, 42083; Primary Aluminum Reduction Plants NESHAP 80 FR 62390, 62398). The commenters also noted that emission reductions were overestimated by the EPA and resulted in overstated reductions to risk.

Response: The finding of unacceptable risks is not based on any one risk metric (*e.g.*, acute hazard quotients), but rather considering all health information available and the degree of uncertainty associated with that information. In the 2015 final rule for Primary Aluminum (Docket ID No. EPA–HQ–OAR–2011–0797), EPA weighed all health risk factors and uncertainties in the risk acceptability determination for the Prebake ovens subcategory. The current acute methodology, while similar between the two rules, is still considered a screening assessment. While the chronic cancer risks for both source categories were comparable, the acute screening methodologies differ and must be weighted in regard to the accuracy and uncertainty of each piece of information in a weight-of-evidence approach for each decision. This relevant body of information is growing fast (and will likely continue to grow even faster), necessitating a flexible weight-of-evidence approach that acknowledges both complexity and uncertainty in the simplest and most transparent way possible. The acute screening risks posed by arsenic are based upon the most up to date review of the REL by EPA and considered the best available benchmark for assessing current risks posed by this pollutant. The application of the acute benchmarks when paired with our acute methodology to assess ''reasonable worst-case one-hour concentrations (*i.e.*, 99th percentile)'' for off-site locations where people maybe present provides a realistic estimate or screen for short-term exposures while we consider EPA's chronic assessment for this source category to be a refined site-specific assessment.

Based on comments and information provided during the comment period, we have updated the estimated control efficiency for both options co-proposed in the 2023 supplemental proposal, and therefore the final rule expected emission reductions are less than those proposed in the 2023 supplemental proposal. We have taken this and all comments into consideration and determined that it is necessary to promulgate a PM emission limit for the combined emissions from the anode refining point source and the Hoboken converter process fugitive capture system pursuant to CAA section 112(d)(6) but not pursuant to CAA section 112(f)(2) because after further consideration and comparison to other source categories, in this specific case, we agree with the commenter that the risk reductions are minimal and that these controls are not necessary to ensure the NESHAP provides an ample margin of safety pursuant to CAA section 112(f). Given the space and infrastructure issues and challenges and effort needed to construct and operate such a new control system at Freeport, we conclude that the facility will likely need up to 3 years to demonstrate compliance with the new standards, which are described in more detail in section IV.B. of this preamble. Given the factors described above, we are finalizing Option 2, with a revised PM emission standard of 4.1 mg/dscm, under the CAA section 112(d)(6) technology review because we conclude that this option represents a development in technologies, processes or practices pursuant to section 112(d)(6). As described in more detail in section IV.B. of this preamble, the baghouse technology to reduce metal HAP emissions at the aisle scrubber identified in the 2023 supplemental proposal is feasible, readily available and already in use at primary copper smelting facilities (including Freeport) as well as in use at facilities in other source categories. We are allowing up to 3 years to comply with this standard because we conclude the facility will need up to 3 years to plan, design, install and operate new controls to reduce emissions from the aisle scrubber. The rationale for our decision to promulgate a standard under CAA 112(d)(6) is described further in section IV.B. of this preamble.

4. What is the rationale for our final approach and final decisions for the risk review?

The EPA sets standards under CAA section 112(f)(2) using ''a two-step standard-setting approach, with an analytical first step to determine an 'acceptable risk' that considers all health information, including risk estimation uncertainty and includes a presumptive limit on MIR of approximately 1-in-10 thousand.[5] If risks are unacceptable, the EPA must determine the emissions standards necessary to reduce risk to an acceptable level without considering costs. A second step follows in which the actual standard is set at a level that provides 'an ample margin of safety' in consideration of all health information, including the number of persons at risk levels higher than approximately 1-in-1 million, as well as other relevant factors including costs and economic impacts, technological feasibility, and other

---

[5] 1-in-10 thousand is equivalent to 100-in-1 million. The EPA currently describes cancer risks as 'n-in-1 million.'

factors relevant to each particular decision.'' As discussed in more detail in the 2022 proposal and in the Benzene NESHAP, there is flexibility regarding factors the EPA may consider in making determinations and how the EPA may weigh those factors for each source category. The EPA conducts a risk assessment that provides estimates of the MIR posed by emissions of HAP that are carcinogens from each source in the source category, the HI for chronic exposures to HAP with the potential to cause noncancer health effects, the HQ for acute exposures to HAP with the potential to cause noncancer health effects,[6] and to assess risks for lead, the EPA compares ambient air concentrations with the lead NAAQS, which is 0.15 ug/m3 based on 3-month rolling averages. The assessment also provides estimates of the distribution of cancer risk within the exposed populations, cancer incidence, and an evaluation of the potential for an adverse environmental effect. (54 FR 38045, September 14, 1989) As discussed in the 2022 proposed rule, the scope of the EPA's risk analysis is consistent with the explanation in EPA's response to comments on our policy under the Benzene NESHAP (54 FR 38057) summarized hereafter: In summary, the EPA's policy permits consideration of multiple measures of health risk including, but not limited to, the MIR, the presence of non-cancer health effects, and the uncertainties of the risk estimates such that these factors can then be weighed in each individual case. The EPA's policy, as discussed in the Benzene NESHAP response to comments, also complies with the Congressional intent behind the CAA.

Thus, the level of the MIR is only one factor to be weighed in determining acceptability of risk. The Benzene NESHAP explained that ''an MIR of approximately one in 10 thousand should ordinarily be the upper end of the range of acceptability. As risks increase above this benchmark, they become presumptively less acceptable under CAA section 112, and would be weighed with the other health risk measures and information in making an overall judgment on acceptability. Or, the Agency may find, in a particular case, that a risk that includes an MIR less than the presumptively acceptable level is unacceptable in the light of other health risk factors.'' Id. at 38045. In other words, risks that include an MIR above 100-in-1 million may be determined to be acceptable, and risks with an MIR below that level may be determined to be unacceptable, depending on all of the available health information.

a. Acceptability Determination

In this final rule, as in the 2023 supplemental proposal and in the 2022 proposal, the EPA concludes that the baseline risks are unacceptable. This determination, as described in the 2022 proposal and the 2023 supplemental proposal, is largely based on the estimated exceedance of the lead NAAQS, along with the maximum acute HQ of 7 for arsenic, which indicate there are significant risks of acute noncancer health effects—especially for children, infants, and developing fetuses, all of whom are particularly vulnerable to chemical exposures as they undergo key developmental processes. Also contributing to this determination, although to a lesser extent, are the inhalation cancer MIRs due to arsenic, with an estimated MIR of 70-in-1 million for actual emissions and 90-in-1 million for allowable emissions, which are approaching the presumptive level of unacceptability of 100-in-1 million.

b. What is EPA requiring in the final rule to address the unacceptable risk?

To address the unacceptable risk, the Agency is promulgating a combined PM emission limit (as a surrogate for HAP metals other than mercury) for process fugitive emissions from roofline vents of a combination of smelting vessels, copper converter departments, slag cleaning vessels and anode refining departments at new and existing sources as proposed in the 2023 supplemental proposal. We are also finalizing the PM emission standard pursuant to CAA section 112(d)(2) and (d)(3) as discussed further in section IV.C. of this preamble. We are also finalizing, as proposed, that compliance would be demonstrated through an initial performance test followed by a compliance test once per year.

c. Remaining Risks After Implementation of the Requirements To Address Unacceptable Risk

To determine the remaining risks after implementation of the new combined PM emission limit to control process fugitive emissions from the roofline vents, we conducted a post-control risk assessment. As described in section IV.A.2., the baseline emissions for the aisle scrubber source at Freeport were corrected and the baseline modeling was conducted again for the final rule along with the roofline vents control option. The revised baseline modeling results, as discussed in section IV.A.2., did not result in any change to the acceptability determination or to the main risk driver under section 112(f) of the CAA. More details on the modeling for the final rule are in the memorandum *Freeport Baseline and Control Options Re-model Risk Analysis Memo*, found in the docket for this action. More details on the modeling analysis for the 2023 supplemental proposal are described in the document *Revised Residual Risk Assessment for the Freeport Smelter (Miami, AZ) in Support of the 2023 Supplemental Proposal for the Primary Copper Smelting Source Category*, available in the docket for this action (Docket ID No. EPA–HQ–OAR–2020–0430–0187).

The post-control modeled risks were updated as described in the memorandum *Freeport Baseline and Control Options Re-model Risk Analysis Memo*, available in the docket for this rule (Docket ID No. EPA–HQ–OAR–2020–0430). The risk assessment after implementing the PM limit for process fugitive emission from roof vents as discussed in this section of this preamble indicates that the modeled lead concentrations would be reduced to 0.06 µg/m3, which is below the NAAQS of 0.15 µg/m3. The MIR at Freeport is reduced from 70-in-1 million to 20-in-1 million and the population with cancer risks greater than or equal to 1-in-1 million is reduced from 21,875 to 16,035. We estimate that at Freeport the maximum chronic noncancer inhalation TOSHI will be reduced from 1 to less than 1 (0.3), and the acute HQ will be reduced from a value of 7 to 2. We estimate that the source category MIR after implementation of the PM limit for process fugitive emissions from roofline vents will be 60-in-1 million, which is the maximum baseline cancer risk near the Asarco facility. We expect that Asarco can comply with the PM standard for process fugitive emissions from roofline vents without additional controls, and therefore it will not achieve emission reductions at Asarco as a result of this PM limit. However, as described in sections III.B. and III.C., and IV.B. and IV.C. of this preamble, we are finalizing a lead limit under CAA sections 112(d)(2) and (3) and design standards under our CAA section 112(d)(6) technology review, respectively, that will achieve reductions of HAP metal emissions at Asarco. We note that the facility already has plans to implement improvements (consistent with the design standards in

---

[6] The MIR is defined as the cancer risk associated with a lifetime of exposure at the highest concentration of HAP where people are likely to live. The HQ is the ratio of the potential HAP exposure concentration to the noncancer dose-response value; the HI is the sum of HQs for HAP that affect the same target organ or organ system.

this final rule) that will reduce their process fugitive emissions of metal HAP as well as SO_2 emissions. In fact, these improvements have been adopted into their most recent state operating permit (finalized in October 2023). As mentioned elsewhere in this preamble, Asarco is currently not operating. However, we expect that these improvement projects will likely reduce the MIR when Asarco returns to operating status.

Based on the post-control risk assessment, we conclude that, after the requirements described in this preamble to address unacceptable risk are implemented, the risks to public health will be reduced to an acceptable level.

d. Ample Margin of Safety Analysis

Under the ample margin of safety analysis, we again considered all of the health factors evaluated in the acceptability determination and evaluated the cost and feasibility of available control technologies and other measures (including the controls, measures, and costs reviewed under the technology review) that could be applied to further reduce the risks due to emission of HAP identified in our risk assessment.

While the additional controls for the combined gas stream from the anode refining department and the Hoboken converter process fugitive capture system identified under the technology review will provide some additional risk reduction, in this case the additional risk reduction is minimal (for example, no change in the cancer MIR of 20-in-1 million), and therefore we are not finalizing this emission standard to provide an ample margin of safety. We conclude that the standards we are finalizing to achieve acceptable risk will also provide an ample margin of safety to protect public health and that, as proposed, a more stringent standard is not necessary to prevent an adverse environmental effect in accordance with CAA section 112(f)(2).

B. Technology Review for the Primary Copper Smelting Source Category

1. What did we propose pursuant to CAA section 112(d)(6) for the Primary Copper Smelting source category?

In the 2022 proposal, as part of our ample margin of safety analysis and technology review, we considered additional controls for the Freeport aisle scrubber which was the second highest contributor to the baseline risks, estimated to represent 23 percent of the MIR. We estimated emission reductions and costs for controlling the combined emissions stream of the anode refining department and Hoboken converter process fugitive capture system (i.e., the aisle scrubber) with a WESP. We also estimated the impacts on risk reductions of these additional controls. The Agency sought comment on this control option but did not propose it in the 2022 proposal. We received comments on the control option for the aisle scrubber as well as additional information from the Freeport facility in response to the EPA's 2022 section 114 information request.

Subsequently, in the 2023 supplemental proposal, based on the comments on the 2022 proposal and the new information from the section 114 information request, the EPA co-proposed regulatory options for additional control of either the Hoboken converter process fugitive capture system or additional control of the combined emissions stream of the Hoboken converter process fugitive capture system and the anode refining department (*i.e.,* aisle scrubber). These standards were proposed as technology developments pursuant to CAA section 112(d)(6) and to provide an ample margin of safety to protect public health pursuant to CAA section 112(f)(2). As described in the 2023 supplemental proposal, the first option (hereafter referred to as Option 1) was the addition of a WESP downstream of the aisle scrubber providing additional control of the combined emissions stream from the Hoboken converter process fugitive capture system and the anode refining department point source (i.e., the same option evaluated by the EPA in our ample margin of safety analysis included in the 2022 proposal). The second option (hereafter referred to as Option 2) was the addition of a baghouse upstream of the aisle scrubber providing additional control of the Hoboken converter process fugitive capture system. As noted in the 2023 supplemental proposal, using performance test data from Freeport we estimated the baseline emissions for the aisle scrubber to be 6.63 tpy metal HAP. We also used these test data as the basis to establish an emissions limit along with an estimate of the expected reductions that would be achieved with the additional controls (i.e., a new baghouse up-stream of current Aisle scrubber or a WESP after the Aisle scrubber). To do this, we first used the data to develop the 99 percent upper prediction limit (UPL). The 99 percent UPL for the combined emissions stream from the anode refining department and the Hoboken converter process fugitive capture system is 7.48 mg/dscm. This UPL served as the baseline for the development of the potential emission standards for each option. Secondly, the UPL value was adjusted (decreased) based on the expected percent reduction that would be achieved by each option. Finally, we estimated costs and risk reductions for each control option. A summary of the options as presented in the 2023 supplemental proposal is included here for reference. Because we proposed these standards under both the technology review authority of CAA section 112(d)(6) and the risk review authority of CAA section 112(f)(2), we estimated risk reductions associated with each of the options consistent with a CAA section 112(f)(2) ample margin of safety analysis and our summary that follows includes those results even though the risk results would not typically be part of the analysis to support a CAA section 112(d)(6) technology review. The summary of the risk reductions presented are the incremental changes attributed to the control option after considering the effects of the implementation of the other risk-based standards in this rulemaking (*i.e.,* the process fugitive roofline vent standards).

For Option 1, we estimated that the control technology could achieve 95 percent emissions reduction which was estimated to be 6.3 tpy metal HAP. The emission limit for this option was 0.374 mg/dscm. The estimated costs were $98.5 million capital costs, $25.2 million total annualized costs, and a cost effectiveness of $4.0 million/ton metal HAP. Risks would be reduced below 1-in-1 million for an additional 1,900 people (the number of people with risk greater than 1-in-1 million would be reduced from 17,400 to 15,500). The maximum acute HQ due to arsenic emissions would be reduced from 2 to 1. The MIR at Freeport (20-in-1 million) and for the source category (60-in-1 million) would be unchanged by this control option.

For Option 2, we estimated that the control technology could achieve 90 percent reduction of the Hoboken converter process fugitive capture system emissions (or 68 percent reduction of the aisle scrubber emissions overall) which was estimated to be 4.5 tpy metal HAP. The emission limit for this option was 2.43 mg/dscm. The estimated costs were $37 million capital costs, $6.2 million total annualized costs, and a cost effectiveness of $1.38 million/ton metal HAP. Risks would be reduced below 1-in-1 million for an additional 700 people (the number of people with risk greater than 1-in-1 million would be reduced from 17,400 to 16,700). The maximum acute HQ due to arsenic emissions would be reduced from 2 to 1. The MIR at Freeport (20-in-1 million) and for the source category (60-in-1 million) would be unchanged by this control option.

The Agency also proposed, in the 2022 proposal, additional work practices to reduce fugitive dust emissions and development of a fugitive dust control plan that must be reviewed, updated (if necessary), and approved by the Administrator or delegated permitting authority. We proposed these requirements in order to provide an ample margin of safety under CAA section 112(f)(2) and as a development in practices pursuant to CAA section 112(d)(6).

With regard to the emission sources at the area source primary copper smelting facility, including sources of fugitive dust emissions, the Agency did not identify any developments in practices, processes, or control technologies. For more details, refer to the document *Technology Review for the Primary Copper Smelting Source Category,* which is available in Docket ID No. EPA–HQ–OAR–2020–0430.

2. How did the technology review change for the Primary Copper Smelting major source category?

Based on comments received during the comment period for the 2023 supplemental proposal, as discussed in more detail in section IV.B.3. of this preamble, we revised our expected emission reductions and control costs for the aisle scrubber control options. A detailed description of the emission reduction estimates and cost estimates associated with these options is provided in the memorandum *Cost Estimates for Additional Controls of Freeport's Aisle Scrubber—REVISED,* which is available in the docket for this rulemaking.

Specifically, for Option 1, we now estimate the control efficiency as 73 percent and estimate emissions reductions of 4.9 tpy metal HAP. We did not amend our cost estimates for this option from those presented in the 2023 supplemental proposal. So, combining our revision to the estimated emission reductions with the costs presented in the 2023 supplemental proposal yields a revised cost effectiveness value of $5.2 million/ton HAP metal. We received additional information from Freeport regarding the costs for site preparation well after the close of the public comment period in a letter dated January 29, 2024, which is available in the docket. In this letter, Freeport estimated costs to demolish and relocate part of the aisle scrubber motor control center (MCC) room, a parking and storage area, and part of the converter maintenance building in order to install a WESP. They estimated these site preparation costs to be $9.2M in capital. As noted above, we received this information about four months after the close of the comment period. Furthermore, the letter did not provide sufficient details to determine the validity of the estimate. Therefore we have not included it in our cost estimates. However, we note that if we did include these costs, the total capital costs would be $108M, the annualized costs would be $26M, and the cost effectiveness would be slightly higher at $5.4M/ton of HAP metal reduced.

For Option 2, we now estimate the baghouse will achieve 61 percent control efficiency of the Hoboken converter process fugitive capture system gas stream and estimate emissions reductions of 3.0 tpy metal HAP (which represents an overall control efficiency of 46 percent for the aisle scrubber). We also revised our cost estimates for Option 2. The revised cost estimates provide a total capital investment of $59.5 million, total annualized costs of $10.8 million and a cost effectiveness of $3.6 million/ton HAP metal. As noted above under Option 1, we received additional information from Freeport, well after the close of the comment period, regarding costs for site preparation in the area where a baghouse would be installed. They estimated it would cost $5.2M to demolish and relocate the anode baghouse MCC room, storage bunkers, and demolition and rerouting of the aisle scrubber piping that is currently located in the area where they estimate the baghouse would be installed. As stated under Option 1, we have not included this cost in our estimates because we received this information well after the close of the comment period and we have insufficient details to evaluate its validity. However, we note that if we did include their estimate for site preparation, the total capital investment would increase to $64.8M, with total annualized costs of $11.5M and a slightly higher cost effectiveness of $3.8M/ton HAP metal reduced.

In addition, we received new information regarding the Asarco facility since publication of the 2023 supplemental proposal. Asarco is located in the Hayden area of Gila and Pinal Counties in Arizona and is the primary source of lead emissions in this area. As discussed in the 2022 proposed rule, the Hayden area is currently designated as nonattainment for the 2010, 1-hour primary SO_2 NAAQS and 2008 lead NAAQS. There have been various regulatory actions to reduce emissions in this area and at the Asarco facility including, but not limited to, a consent decree between EPA and Asarco to bring the facility into compliance with the NESHAP by December 2018 and revisions to the state implementation plan (SIP) to help achieve attainment of the lead NAAQS by October 2019. However, effective March 2, 2022, the EPA determined that the Hayden lead nonattainment area failed to attain the 2008 lead primary and secondary lead NAAQS and the 2010 1-hour primary SO_2 NAAQS (87 FR 4805, January 31, 2022) by the applicable date of October 3, 2019. As a result, the State of Arizona is required to submit revisions of the SIP to EPA. As part of this process, EPA Region 9 staff informed the EPA Office of Air Quality Planning and Standards staff in October 2023 of several projects that Asarco has planned as part of the most recent SIP revisions and that ADEQ has adopted into Appendix A of Asarco's operating permit (October 3, 2023), which is available in the docket for this action. The projects include engineering controls and work practices which Asarco estimates will reduce fugitive metal HAP emissions at the facility. The projects that are in Asarco's operating permit include the following:

- *Flash Furnace Control System:* This project involves installing and ventilating a partial enclosure around the Inco flash furnace uptake shaft to improve the capture of process fugitives.
- *Fuming Ladle Capture System:* This project involves the construction of a hood and retaining walls to improve capture of process fugitives from fuming ladles.
- Anode Furnace Secondary Hood Capture and Control System: This project involves the construction of secondary hoods to improve capture and then ducts the emissions to a planned new anode secondary hood baghouse.

These projects will help ensure that process fugitive metal HAP roofline emissions would be reduced and will ensure that the roofline emissions at Asarco can meet a lead limit of 0.326 lb/hour, which is based on modeling demonstration submitted by the facility to the state in support of a revision to the lead SIP. We expect no additional costs to comply with the lead limit other than compliance testing costs. The lead limit is further discussed in section IV.C.2.

3. What key comments did we receive on the technology review, and what are our responses?

Comment: Commenters objected to the EPA's change in position in the supplemental proposal about using a WESP to control aisle scrubber emissions. The commenters stated that the EPA rejected the technology in the 2022 proposal yet co-proposed it as an option in the 2023 supplemental proposal. Commenters stated that in the 2022 proposal, the EPA concluded with regards to using a WESP to control aisle scrubber emissions that ''[g]iven the relatively high estimated capital costs, uncertainties, and moderate risk reductions . . . the Agency is not proposing these additional controls'' under the ample margin of safety analysis. Yet in the supplemental proposal the EPA stated the ''cost impacts'' of $4.0 million/ton metal HAP for a WESP are ''reasonable.'' The commenters point out the new cost effectiveness in the supplemental is more than 2 times the cost effectiveness that the EPA considered excessive for a WESP in the 2022 proposal, and that it far exceeds the precedent set in the recent Coke Oven proposed NESHAP revisions, where the agency found that $1.3 million/ton is the reasonable upper threshold of cost effectiveness for nonmercury metal HAP.

In addition to objecting to the EPA's change of position on using a WESP, another commenter stated that the EPA overestimated the achievable removal efficiency for a WESP in the dilute, high volume gas stream at the aisle scrubber. The commenter asserted that the actual removal efficiency would be 60 percent, rather than the 95 percent estimated by the EPA. The commenter performed their own estimate of emission reductions and cost and estimated a cost effectiveness of $6.3 million/ton HAP metal. Other commenters expressed support for using a WESP to control aisle scrubber emissions as it would reduce metal emissions from the converter department and the anode refining department. The commenter stated that while the EPA does not express a preference for either the WESP or baghouse option, the WESP-based limit is consistent with the Clean Air Act, while the baghouse-based limit is not. Clean Air Act section 112(d)(2) expressly provides that the EPA's air toxics standards must require the ''maximum'' reduction that is ''achievable'' considering cost and other statutory factors. As such, both proposed limits are achievable considering cost and other statutory factors, however, the ''maximum'' degree of reduction that is achievable is the one provided by the WESP-based limit. The commenter also noted the WESP-based limit would yield substantially greater reductions in metal HAP emissions (6.3 tpy as opposed to 4.5 tpy from the baghouse-based limit) and would reduce cancer risk below 1-in-1 million for 1,900 people, whereas the baghouse-based limit would reduce cancer risk below 1-in-1 million for only 700 people. Another commenter added that emissions from smelters are virtually certain to increase in the future as the demand for copper increases, which means that the difference in reductions in using a WESP versus a baghouse will also increase. The commenter stated that the cost effectiveness ''of the WESP option will increase relative to the baghouse option, therefore, the EPA should issue a strong limit based on the reductions that are achievable with a WESP.'' Several commenters stated that the San Carlos Apache Tribe is directly impacted by both major source smelters, and emissions of lead and arsenic are of particular concern due to their persistent and bioaccumulative nature. The same commenters stated their support for the WESP option to achieve maximum emission reductions. These commenters also claimed that EPA underestimated the emissions of lead and other pollutants from the copper smelters based on a comparison to Toxics Release Inventory (TRI) data. One commenter provided TRI estimates for lead from the Freeport smelter, stating ''In 2020, for example, the Freeport smelter alone reported emitting more than 14 tons of lead. In 2019, it reported emitting 21 tons of lead and, in 2018, it reported emitting more than 29 tons of lead . . .''.

Response: In the 2022 proposal, we stated that we were not proposing the WESP control option at that time, however we solicited comments regarding our analysis and whether we should establish more stringent standards to reduce HAP metal emissions from the aisle scrubber. We also subsequently requested in a 2022 section 114 information request that the Freeport facility perform feasibility analyses for additional control of the aisle scrubber. In response to the 2022 proposal, we received comment that we should establish more stringent standards to reduce HAP metal from the aisle scrubber. Therefore, we used the new information collected during the comment period and from Freeport's response to the CAA section 114 information request to develop the WESP and baghouse options presented in the 2023 supplemental proposal.

Based on comments we received on the 2023 supplemental proposal, we also revised our emission reductions estimates for the WESP. As described in the 2023 supplemental proposal, the expected control efficiency for the WESP was 95 percent, however, we acknowledge that a number of factors can affect control efficiency, including the particulate concentration of the inlet stream to the control device. The aisle scrubber handles a high volume of gas (flowrate of approximately 1 million actual cubic feet per minute) and low particulate loading relative to the flowrate. We agree with commenters that the low concentration of particulate in the exhaust stream of the aisle scrubber, which would be the inlet to the WESP, may present technical feasibility issues in achieving a 95 percent reduction. Therefore, we updated our estimates of emission reductions. As detailed in the technical memorandum *Cost Estimates for Additional Controls of Freeport's Aisle Scrubber—REVISED*, which is available in the docket for this rulemaking, we back-calculated the control efficiency of the WESP by assuming the aisle scrubber exhaust particulate would be reduced to 1 milligram per cubic meter (mg/m^3) by the WESP, which is an assumed minimum outlet concentration for this control technology. Based on this back-calculation, the resulting control efficiency of the WESP is 73 percent. Applying this revised control efficiency to the baseline emissions for the aisle scrubber (6.63 tpy metal HAP) yields an estimated reduction of 4.9 tpy metal HAP. We did not receive information during the 2023 supplemental proposal comment period on our total annualized costs for the WESP option. Therefore, when we combine the revised emission reductions (4.9 tpy metal HAP) with the total annualized costs ($25.2 million) presented in the 2023 supplemental proposal for the WESP option, the cost effectiveness is $5.2 million/ton HAP metal.

As described in this final rule preamble, we have concluded that, after taking public comment into consideration and making the appropriate revisions to our estimates, the costs for Option 1 are not reasonable. For this reason and others discussed in this preamble, we are not promulgating the WESP option.

In regard to comments on Tribal impacts and their concerns about lead and arsenic, the EPA recognizes the concerns of Tribal commenters and their representatives and we have taken their comments into consideration in this action. With regard to impacts, although the EPA determined that risks due to HAP emissions are unacceptable at baseline for populations living close to the Freeport facility, the EPA's risk assessment completed for this source category indicates that health risks due to HAP emissions from primary copper smelting sources on Tribal lands, which are further away (about 10 miles from the facility) are well within acceptability at baseline. After the amendments in this final rule are implemented, the NESHAP will provide an ample margin of safety for all populations, including the San Carlos Apache Tribe. More information regarding the estimated health risks due to lead and arsenic emissions to humans at baseline (due to current emissions) and post-control (due to emissions after the amendments in this action are implemented) are described in sections III.A. and IV.A. of this preamble, and the estimated impacts to various demographic groups are described in section V.F. of this preamble. More details of the risk assessment are available in the document titled *Residual Risk Assessment for the Primary Copper Smelting Major Source Category in Support of the 2021 Risk and Technology Review Proposed Rule,* which is available in the docket.

Regarding the comments supporting the addition of WESP to control HAP metal emissions, for the reasons described elsewhere in this preamble, we are not promulgating the WESP option and are promulgating the baghouse option for the aisle scrubber. We estimate that the amendments in the final rule will reduce total metal HAP emissions (primarily lead and arsenic) by 8 tpy for the major source category.

Regarding the TRI emissions estimates provided by the commenter compared to our estimates, we estimate that the two major source facilities currently emit a total of 16.7 tpy of metal HAP (the majority of these emissions are from Freeport). We estimated these emissions primarily using test data provided by the facility for the sources subject to the Primary Copper Smelting major source NESHAP. The TRI is a ''whole facility'' inventory, which means that it includes estimates of stack and fugitive air emissions for all HAPs that are emitted at the facility which also include emissions from non-source category processes. Our emission estimates include those applicable to the primary copper smelting source category only. However, as noted in previous paragraph, this final rule will achieve an estimated reduction of 8 tpy of HAP metals, therefore after these amendments to the NESHAP are implemented, total estimated emissions will be about 8.7 tpy for the major source category.

Comment: Commenters stated that the EPA erroneously describes their facility's converters as having ''primary and secondary capture systems and controls, but no tertiary controls.'' According to the commenter, Hoboken converters use a side-flue intake capture system, and the roofline canopy system (installed in 2017 as part of facility-wide improvements to ensure the Miami area's compliance with revised standards for SO_2) is properly described as a tertiary capture system. Therefore, the commenter noted that the proposed standards would not appropriately apply to the converters at their facility as they do not have ''secondary capture systems.''

Response: We have corrected the characterization of the capture and control systems for converters at the Freeport facility in the preamble and regulatory text associated with the final rule.

Comment: Several commenters asserted that the aisle scrubber standards are not justified pursuant to section 112(d)(6). The commenters argued that the EPA has not identified any ''developments in practice, processes or control technologies'' since the original publication of the Primary Copper Smelting NESHAP that would justify additional controls on the aisle scrubber. Commenters noted that the EPA cites section 112(d)(6) to claim that ''developments'' warrant the imposition of new controls, but the EPA fails to recognize that section 112(d)(6) only authorizes revisions that are ''necessary.'' The commenter asserted the word ''necessary'' cannot be ignored, and that it clearly requires some showing of necessity beyond the identification of ''developments'' because the mere existence of a development does not make it ''necessary.'' According to commenters, the fact that the term ''developments'' is found only in a parenthetical confirms it is merely one component of the analysis that ultimately must conclude a revision to a standard is ''necessary,'' a showing that the EPA has not made here.

Response: We disagree that, in this case, additional controls to reduce emissions at the aisle scrubber are not necessary. The aisle scrubber stack was identified in the 2022 proposal as one of the largest sources of metal HAP emissions at Freeport. We currently estimate it emits 6.63 tpy of HAP metals (primarily lead and arsenic). The aisle scrubber is a control device that is mainly used to control SO_2 emissions. This device controls emissions from the anode refining point source and emissions from the Hoboken converter process fugitive capture system. The anode refining point source gas stream passes through a PM control device (*i.e.,* a baghouse) before entering the aisle scrubber for SO_2 control, but the converter process fugitive capture system is ducted directly to the aisle scrubber without PM control prior to the aisle scrubber. We identified and proposed in the 2023 supplemental proposal 2 options to reduce metal HAP emissions from the aisle scrubber stack at Freeport. Our analysis shows that the technologies to reduce metal HAP emissions at the aisle scrubber identified in the 2023 supplemental proposal are readily available and already in use at primary copper smelting facilities (including Freeport) as well as in use at facilities in other source categories. This is especially true for baghouses. Regarding the WESP, although this technology has been applied at some emissions points at these facilities and other metals sectors (*e.g.,* Secondary Lead Smelters), we are not aware of the WESP being successfully applied to emissions sources similar to the aisle scrubber. Specifically, the aisle scrubber has a very high flow rate and low concentration of PM compared to other point source emissions sources where the WESP has been applied.

Another factor we considered in our decision is that the Asarco facility has a secondary hood capture system to collect secondary emissions from their Peirce-Smith converters and that secondary hood capture system is vented to a baghouse for PM control (which also controls metal HAP emissions). We find these PM controls are especially important for lead and arsenic because these two pollutants are persistent, bioaccumulative and highly toxic HAPs.

Given all of this information, we conclude that additional PM controls are necessary to further reduce metal HAP at the aisle scrubber source, and that the baghouse technology that we proposed in the 2023 supplemental proposal (*i.e.,* Option 2 in the supplemental proposed rule) represents a development that will further reduce metal HAP emissions at Freeport. The baghouse is a common, well demonstrated technology used to control PM emissions from various industrial emissions sources.

Comment: One commenter was supportive of the baghouse option despite expressing a preference for the WESP option.

Other commenters were opposed to the baghouse option. These commenters noted that the cost effectiveness of this option exceeds the threshold for cost effectiveness for nonmercury metal HAP despite being underestimated. Commenters stated that the EPA overstated emission reductions and underestimated costs by about a factor of 2.

Commenters asserted that the EPA overstated the emission reductions from this option. One commenter explained that due to the high volume of the exhaust stream and the low particulate concentration in the exhaust stream (estimated to be on the order of 0.001 gr/ft^3), control efficiency is expected to be closer to 50 percent, rather than the 90 percent used by the EPA. The commenter explained this is because they are not aware of any vendor guarantee of a minimum exhaust concentration of 0.0001 gr/ft^3 which would be required to achieve 90 percent control.

Commenters provided their own estimate of the baghouse costs of $70–88 million and noted that the discrepancy between their estimate and the EPA's estimate in the supplemental proposal (which differed by about a factor of 2) can be attributed to: under sizing and, thus, underestimating costs for ductwork; using a shaker instead of more modern pulse jet style baghouse; using too small of a scaling factor to size the baghouse; underestimating the cost of the lime injection system; omitting indirect costs (*e.g.,* freight, spare parts, engineering procurement and construction management services, equipment rental); and omitting contingency which the commenter included at a value of 25 percent. Using their own emission reduction estimates of 2.5 tpy HAP metal and total annualized cost estimates ranging from $12.7M to $14.5M (with 25 percent contingency included), commenters estimated the cost effectiveness value for this option as being between $4.8 to $5.8 million/ton HAP.

Response: As described in the previous comment response, we conclude that additional PM controls are necessary to further reduce metal HAP at the aisle scrubber source, and that the baghouse technology represents a development that will further reduce metal HAP emissions at Freeport. To inform our decision under the technology review, we evaluated the types of technology used in the industry and other source categories. We found that baghouse technology is readily available, feasible, well demonstrated and is being used to control a similar source at the other major source primary copper smelter in this source category. However, we have revised our emission reductions estimates and our cost estimates for this option after considering the comments.

As described in the 2023 supplemental proposal, for a baghouse we generally expect achievable control efficiencies to be at least 90 percent. We acknowledge that a number of factors can affect the control efficiency, including the particulate concentration of the inlet stream to the control device. Based on the engineering evaluation provided by Freeport in their 2022 section 114 information collection request response, the Hoboken converter process fugitive capture system has a high flowrate and low particulate loading relative to the flowrate. We agree with commenters that the expected concentration of particulate in the inlet stream may present technical feasibility issues achieving a 90 percent reduction. Therefore, we updated our estimates of emission reductions.

First, we note that through CAA section 114 information requests for other EPA rules (*e.g.,* electric arc furnaces (EAF), foundries), we have collected data demonstrating that baghouses achieve average particulate outlet concentrations below 0.001 grains per dry standard cubic feet (gr/dscf). We found that baghouses with similar flowrates to those expected for the Hoboken process fugitive capture system in the EAF source category achieve, on average, outlet concentrations of filterable particulate of 0.0006 gr/dscf with a range of 0.0001 to 0.0017 gr/dscf. For foundries, there were 2 facilities that were used to set the new source standard which had average PM emissions of 0.0002 gr/dscf and a high value of 0.0004 gr/dscf. The other had an average of 0.0008 gr/dscf and a high value of 0.00086 gr/dscf. Considering this information and the information provided in Freeport's engineering evaluation for the Hoboken converter process fugitive capture system, we back-calculated the control efficiency of the baghouse assuming that the Hoboken converter process fugitive capture system particulate would be reduced to 0.0005 gr/dscf which is an assumed achievable outlet concentration for this control option when estimating the control efficiency. The expected baghouse flowrate was taken from the Freeport engineering analysis, and the particulate loading was assumed to be 75 percent of the aisle scrubber outlet. The resulting control efficiency is 61 percent. Applying this revised control efficiency to the baseline emissions for the Hoboken converter process fugitive capture system (assumed to be 75 percent of the aisle scrubber or 4.97 tpy metal HAP) yields an estimated reduction of 3.0 tpy metal HAP. The expected reduction is 46 percent of the aisle scrubber emissions overall, after the Hoboken converter process fugitive capture system baghouse stream combines with the controlled anode refining department stream in the aisle scrubber.

Next, concerning costs, we have updated our cost estimates after considering the comments. We revised the estimated costs for total capital investment to include those costs provided by the commenter for equipment supply. We utilized the EPA cost control manual to estimate all indirect costs including contingency in accordance with section 6, Chapter 1—Baghouses and Filters. The revised cost estimates provide a total capital investment of $59.5 million and total annualized costs of $10.8 million. Using our emission reduction estimate and the total annualized cost estimate, the cost effectiveness is $3.6 million/ton metal HAP reduced.

While this cost effectiveness is higher than we have accepted in the past for reducing metal HAP in some standards, there are other relevant factors that EPA can consider, and has considered. The highest cost effectiveness accepted in the past was $1.5M/ton of metal HAP in 2009 dollars (which is about $2M/ton of metal HAP in 2022 dollars) in the Secondary Lead Smelting NESHAP (77 FR 556, January 5, 2012). However, it is important to note that EPA considers other factors besides cost-effectiveness when considering requirements under the technology reviews, such as feasibility of controls, how well certain controls have been demonstrated, and overall economic impacts. In this case, as described previously in this section, we determined that baghouse technology is readily available, feasible, well demonstrated and is being used to control a similar source at the other major source primary copper smelter in this source category. Furthermore, in this specific case, we have collectively considered the significant emission reductions of persistent, bioaccumulative, and toxic (PBT) HAPs (primarily lead and arsenic, which are both PBT HAPs), non-air environmental impacts, feasibility concerns, and the costs of each of the options. We note that lead and arsenic are known developmental toxicants that can cause particular harm to infants, children, and the developing fetus. Furthermore, arsenic is classified as a human carcinogen by the EPA and the World Health Organization. In addition, we do not expect that the overall economic impacts of this rule will lead to significant changes in domestic copper production; the market price for commercial grade copper or any products comprised of copper inputs; or employment, as described in section V.D. of this preamble. This rationale and these considerations are discussed in more detail in section IV.B.4. of this preamble.

The details of our emission reduction estimates and cost estimates have been provided in the technical memorandum *Cost Estimates for Additional Controls of Freeport's Aisle Scrubber—REVISED*, which is available in the docket for this rulemaking.

4. What is the rationale for our final approach for the technology review?

As noted in section IV.A. of this preamble, we updated our risk modeling based on the revisions to the expected emission reductions for each of the options proposed in the 2023 supplemental proposal. We conclude that, in this case, the risk reductions achieved are not sufficient to promulgate this standard (*i.e.*, the PM limit for the Aisle scrubber described previously in this section) pursuant to CAA section 112(f); however, we continue to maintain that baghouses are proven technologies for achieving high degrees of particulate control. We also find that additional controls on similar exhaust streams are used in the source category. As discussed in section IV.B.3. of this preamble, the aisle scrubber stack is one of the largest sources of metal HAP emissions at Freeport. We estimate it emits 6.63 tpy of HAP metals (primarily lead and arsenic). The aisle scrubber is a control device that is mainly used to control SO_2 emissions from the anode refining point source and from the Hoboken converter process fugitive capture system. While the anode refining point source gases are vented to a PM control device before entering the aisle scrubber, the gas stream from the Hoboken converter process fugitive capture system vents directly to the aisle scrubber without prior PM control. We conclude that further reduction of metal HAP emissions from the aisle scrubber are necessary and that there are developments in practices, processes, or control technologies that will achieve further reductions of metal HAP emissions at Freeport. The PM controls on this source are especially important for reducing lead and arsenic because these two pollutants are PBT HAPs.

To inform our decision under the technology review, we evaluated the types of technology used in the industry and in other source categories to control PM emissions. As discussed in this preamble, we proposed two options in the 2023 supplemental proposal: Option 1 evaluated a tighter PM limit based on the application of a WESP downstream of the aisle scrubber and Option 2 evaluated a tighter PM limit based on using baghouse technology upstream of the aisle scrubber. We next analyzed the technical feasibility, estimated costs, and non-air environmental impacts for each option. As described in section IV.B.3. of this preamble, we are not aware of a WESP (Option 1) being successfully applied to emissions sources similar to the aisle scrubber, which has a very high flow rate and low concentration of PM compared to other point source emissions sources where the WESP has been applied. As described previously in this preamble, we determined that baghouse technology (Option 2) is readily available, feasible, and is being used to control a similar source at the other major source copper smelter in this source category.

With regard to feasibility, the Freeport facility property does not extend far beyond its core manufacturing operations and is bordered on one side by a railroad track; therefore, space to install large equipment such as that required in either option is limited. In their feasibility analysis for these control options, Freeport explained that Option 1 requires a larger footprint than Option 2. We also considered the secondary impacts of the two control options and found that Option 1 would require the use of significant amounts of water, which is of particular concern because the facility is located in an arid climate where water resources are limited.

As is permitted under CAA section 112(d)(6), we also considered the costs of each option. The cost estimates for the WESP option include a total capital investment of $98.5M and total annualized costs of $25.2M. With an estimated reduction of 4.9 tpy of total metal HAP emissions, we estimate the cost effectiveness of installing a WESP is $5.2M/ton of HAP metal reduced. We have updated our cost and emission reduction estimates for the baghouse option after considering the comments as described in section IV.B.3. The revised cost estimates include a total capital investment of $59.5 million and total annualized costs of $10.8 million. Using our emission reduction estimate of 3.0 tpy and the total annualized cost estimate, the cost effectiveness is $3.6 million/ton metal HAP reduced for the baghouse option (Option 2).

In collectively considering the emission reductions, secondary impacts, feasibility concerns, and the costs of each of the options, we find that Option 2 provides sizeable reductions of HAP metals, including two highly toxic persistent bioaccumulative HAPs (i.e., lead and arsenic) at reasonable costs while minimizing secondary impacts and feasibility concerns. Therefore, taking into consideration the comments and other information and data as well as the other factors discussed in this preamble, we are promulgating a PM standard of 4.1 mg/dscm for the combined emissions stream from the Hoboken converter process fugitive capture system and the anode refining department (*i.e.*, the aisle scrubber) pursuant to CAA section 112(d)(6). We estimate this will reduce HAP metal emissions by 3.0 tpy.

A detailed description on the development of this emission standard is provided in the memorandum *Final Emission Standard Development* for the Aisle Scrubber, which is available in the docket for this rulemaking.

In the 2022 proposal, additional work practice standards to minimize fugitive dust and development of a fugitive dust control plan that must be reviewed, updated (if necessary), and approved by the Administrator or delegated permitting authority were proposed. These standards were proposed in order to provide an ample margin of safety to protect public health and pursuant to CAA section 112(d)(6). In this specific case, for the Primary Copper Smelting source category, we have decided to promulgate the additional work practices to minimize fugitive dust and the development of a fugitive dust control plan under only the technology review. The work practices and dust plan requirements are the same as proposed in the 2022 proposal. The fugitive dust plan and work practices are appropriate under CAA section 112(d)(6) because they are practices that will ensure emissions will be minimized. It is our understanding that the facilities are already doing these types of practices so, although these measures are anticipated to further address fugitive emissions and advance the goal of minimizing HAP metal emissions, we are unable to quantify and assure significant enough reductions in actual emissions that would significantly reduce health risk; therefore, we are not promulgating under CAA 112(f) in this particular case. We expect that since facilities are already implementing most of the additional work practices as part of requirements in the facility's operating permit or to comply with consent decree, there will be minimal additional costs to comply with the final rule work practices and fugitive dust plan requirements. The only additional costs would be a slight increase related to recordkeeping and reporting requirements. For details on the work practices see the 2022 proposal preamble (87 FR 1616).

As noted in section IV.A.3., one of the commenters took issue with the aisle scrubber standard being applied only to the Freeport facility when their post-roofline control MIR is 20-in-1 million. They stated that roofline controls to achieve acceptable risk leave the MIR for the other major source copper smelter (Asarco) ''untouched'' at 60-in-1 million, asserting this is ''unfair, arbitrary and capricious, and unsupported by the record.'' After considering this comment, our prior proposals, and the information in the record, we evaluated options under CAA section 112(d)(6) and 112(d)(2) and (3) to reduce process fugitive emissions from Asarco. In the 2022 proposal, we solicited comment on a BTF limit to control process fugitives from the flash furnace roofline vent to reduce risk at Asarco. We estimated that to comply with a BTF limit, the facility would need to install improved capture and control of the flash furnaces as well as the large ladle containing hot liquid matte from the flash furnace taping/pouring operations, called the fuming ladle. In our cost estimates, we assumed a new baghouse would be needed as well as a roofline ventilation capture system. We did not receive comments on this specific BTF standard or our cost estimation. However, as noted above in this paragraph, we did receive the general comment that said our proposal would do nothing to reduce the MIR of 60-in-1 million at Asarco.

Nevertheless, as described in section IV.B.2., we received new information regarding developments in technology (3 projects to reduce process fugitive emissions from roof vents) currently planned for the Asarco facility (and have been incorporated into their state permit and draft SIP), which are estimated to achieve a 30 percent reduction in process fugitive metal HAP emissions from the roofline vents. We have reviewed this information and agree that these developments will reduce fugitive metal HAP emissions. We estimate, based on the roofline vent metal HAP emissions estimates we had for the 2022 proposal and applying a 30 percent reduction, that the total process fugitive metal HAP emissions (including lead and arsenic, which are persistent, bioaccumulative HAPs) from the roofline will be reduced by 0.39 tpy. These estimates are available in the docket for this action (see memorandum *Cost Estimates for Enhanced Capture and Control of Process Fugitive Emissions at Asarco*). We expect that the reductions in process fugitive metal HAP emissions will also reduce risk; however, we have not yet quantified this risk reduction because the facility is not currently operating and their future operational emission profile may be different than what we have modeled in support of the 2022 proposed rule. Furthermore, we received this information regarding the three projects well after the end of the comment period and therefore we did not have sufficient time to remodel and calculate the risk reductions that will be achieved.

With regard to cost impacts, we estimate that for the facility to comply with these design standards (and comply with the lead limit, promulgated under CAA section 112(d)(2) and (3), which is discussed in section IV.C.2. of this preamble), the facility will need to install improved capture and control consistent with what is expected under the state permit and SIP. As mentioned in section IV.B. of this preamble, the improvements needed to comply with the design standards and emissions limit are already adopted into the facility's operating permit and therefore costs impacts are already expected regardless of the requirements we are including in this final rule. However, since the facility has not yet begun construction for these improvements, we estimated costs for these projects as part of this action. We estimate that the total costs for complying with the design standards and lead emission limit are $15.4M in capital costs and $3.9M in annualized costs. Asarco provided estimated costs for these projects in a letter provided on February 26, 2024, which is available in the docket for this action. They estimate total capital costs of $22.4M and $5.8M in annualized costs for all three projects. Given the late submittal and the court-ordered promulgation deadline of May 2, 2024, we did not have sufficient time to review these estimates and determine their validity. However, we note again that the projects are already requirements in their operating permit and the facility is already expecting to incur these costs unrelated to the NESHAP. More details on the estimated costs are found in the memorandum Cost Estimates for Enhanced Capture and Control of Process Fugitive Emissions at Asarco, which is available in the docket for this action. To achieve reduction of HAP metals at Asarco, we are finalizing design standards consistent with their 2023 operating permit which include improved capture and control of the Peirce-Smith flash furnaces, fuming ladles, and anode furnaces.

C. CAA Sections 112(d)(2) and (3) Revisions for the Primary Copper Smelting Source Category

1. Anode Refining Point Source Emissions

a. What did we propose for the anode refining point source pursuant to CAA section 112(d)(2) and (d)(3)?

We proposed a MACT floor PM limit as a surrogate for metal HAP in 40 CFR 63.1444(i) (finalized at 40 CFR 63.1444(f)) for new and existing anode refining departments in the 2022 proposal. The MACT floor emissions standard for new and existing sources, 5.78 mg/dscm, was developed based on the 99 percent UPL for PM emissions from the available emissions data (which was from Asarco) and represents the MACT floor level of control. We considered beyond-the-floor options for the standard, but we did not identify any feasible, cost-effective beyond-the-floor options. It should be noted that at the Freeport facility, the anode refining department gas stream and the Hoboken converter process fugitive capture system exhaust stream are both routed to and combined in the aisle scrubber from which they are emitted to the atmosphere. The facility conducts performance tests after the anode refining department stream is combined with the Hoboken converter process fugitive capture system exhaust stream (*i.e.*, at the aisle scrubber outlet). Therefore, the EPA also proposed amendments to the existing alternative emission limit in 40 CFR 63.1446 to include the anode refining department stream, as we expected Freeport would be able to use this option to demonstrate compliance with the anode refining department emission limit at the aisle scrubber outlet. Lastly, we proposed in 40 CFR 63.1451(a) and 63.1453(a), respectively, that compliance with the PM emissions limit for the anode refining department will be demonstrated through an initial performance test followed by a compliance test at least once per year.

b. How did the anode refining point source revisions made pursuant to CAA section 112(d)(2) and (3) change since proposal?

There are no changes to the emission standard for the anode refining point source since the proposals, except that we rounded the 5.78 mg/dscm to 2 significant figures (*i.e.*, 5.8 mg/dscm). We are promulgating the MACT floor-based PM emission standard of 5.8 mg/dscm for the anode refining department point source emissions (*i.e.*, emissions exiting the anode baghouse) and related compliance requirements, as proposed in the 2022 proposal. However, because Freeport combines their anode refining point source emissions with the fugitive capture system from the Hoboken converters, we are also finalizing, as proposed, to include the anode refining department point source emissions as an emission source to be included in the alternative emission limit calculation for the combined stream.

Additionally, in the final rule based on comments, we are also providing that facilities that combine the anode refining department and Hoboken converter process fugitive capture system streams must comply with the combined stream PM limit of 4.1 mg/dscm and related compliance requirements to demonstrate compliance with the anode refining department emission standard and related compliance requirements. As discussed in section IV.B. of this preamble and pursuant to CAA section 112 (d)(6), we are finalizing a PM emission standard of 4.1 mg/dscm for the combined stream of the anode refining department and Hoboken converter process fugitive capture system and an annual compliance testing requirement.

c. What key comments did we receive on the proposed anode refining point source revisions made pursuant to CAA section 112(d)(2) and (3) and what are our responses?

Comment: One commenter stated that the EPA should set the PM MACT floor based on a concentration limit of 23 mg/dscm, which is an existing technology-based limit for similar emission points in the current NESHAP rather than the 99 percent UPL emission standard developed using only data from Asarco. The commenter explained that this limit should be applied at their aisle scrubber stack, which is the emission point for emissions from their Hoboken converter process fugitive capture system and their anode refining department, thus each affected source would be subject to the same 23 mg/dscm limit. The commenter added that the EPA does not have sufficient data to set a mass rate for the anode refining department MACT floor since the only data used to set the limit are from Asarco, which does not reflect the operating performance of their anode refining department and does not reflect the best 5 sources as is required by the EPA's procedure for source categories with less than 30 sources. The commenter explained that they cannot provide performance tests of their anode refining department emissions using EPA methods because of the duct configuration of the baghouse controlling these emissions. However, in their comment letter they submitted an engineering evaluation which characterized the flowrate and particulate emissions for the anode refining department's baghouse. The engineering evaluation was not conducted following EPA methods. The commenter used the data from the engineering evaluation with the data the EPA used in the development of the 99 percent UPL (*i.e.*, Asarco's data) to estimate a revised MACT standard, 7.3 mg/dscm. The commenter stated that the purpose of the recalculation of the MACT standard was to demonstrate their argument that more data collection is necessary to support the development of a representative MACT standard for the anode refining department.

Response: First, as described in the preamble of the 2022 proposal, the emission standard for the anode refining point source was proposed pursuant to CAA section 112(d)(2) and (3). This standard is not being proposed pursuant to CAA section 112(d)(6). The 1998 proposal for primary copper smelting identified the anode refining department in the definition of primary copper smelters; however, the EPA did not have sufficient data at the time to set a standard for this emission source. In contrast, in the 2007 area source NESHAP for primary copper smelting, data were available to set an emissions standard for the anode refining department. With the recently acquired Asarco data, we now have sufficient data to develop a MACT floor emission standard for the anode refining point source at major sources. The Asarco data includes 9 data points, which exceeds the minimum sample size of 3 data points necessary to develop a MACT floor. Therefore, we disagree that we have insufficient data to develop the emission standard. We also do not find the data included in Freeport's engineering evaluation appropriate to include in the MACT floor dataset since these data were not collected following EPA methods. In regard to the comment that the MACT floor limit does not reflect the best 5 sources, there are only two major sources in this category, and as stated, only one of these major sources had valid data from an anode refining department. We used all available valid data from the best performing sources for which the EPA could reasonably obtain emissions information in the category, which is in accordance with CAA section 112 (d)(3)(B).

Comment: One commenter explained that the configuration of their anode refining department baghouse makes the proposed test methods infeasible. The commenter stated that the anode refining department exhaust at their facility is controlled by a baghouse, which is ducted to the aisle scrubber where it combines with exhaust from the facility's Hoboken converter process fugitive capture system. The point of emission for their anode refining department exhaust is the outlet of the aisle scrubber. The commenter stated implementing the alternative emission limit option to comply with the anode refining limit (as proposed by the EPA) is not feasible due to the inability to measure flowrate using EPA Method 1 in the duct between the baghouse outlet and aisle scrubber inlet. The commenter explained the ductwork does not have enough straight passes to measure flowrate according to EPA Method 1.

Response: Based on reviewing information submitted by the commenter and observations made by the EPA during a November 7, 2023, site visit to the facility, the EPA agrees that there is currently no viable testing location for flowrates using EPA Method 1 from the anode refining department baghouse to the aisle scrubber. In light of this new information, we agree that the use of the alternative emission limit is not an option for demonstrating compliance with the anode refining department for this facility. However, this alternative emission limit procedure may be appropriate at a new facility; thus, we are finalizing the proposed amendment to add the anode refining department to the list of emission sources which could be included in the emission alternative limit calculation option. However, as discussed elsewhere, we are promulgating a limit for the combined stream of the anode refining department and Hoboken converter process fugitive capture system (*i.e.*, the Freeport aisle scrubber). Based on the data provided by the Freeport facility in their section 114 information request response, an estimated 75 percent of the particulate emissions emitted from the aisle scrubber are from the Hoboken converter process fugitive capture system while the remaining 25 percent are from the anode refining baghouse. The emission standard for the combined stream of the anode refining department and Hoboken converter process fugitive capture system based on 61 percent control of the emissions by a baghouse controlling the emissions from the

Hoboken converter process fugitive capture system is 4.1 mg/dscm. The emission standard for the combined stream of the anode refining department and Hoboken converter process fugitive capture system is more stringent than the anode refining department emission standard alone (5.8 mg/dscm). Therefore, we are finalizing that compliance with the emission standard for the combined stream of the anode refining department and Hoboken converter process fugitive capture system demonstrates compliance with the anode refining department emission standard.

Comment: One commenter stated that in the 2022 proposal the EPA proposed a new MACT floor limit for the anode refining department. The commenter requested clarification if the PM limits for the aisle scrubber in the 2023 supplemental proposal replace the anode refining department limit in the 2022 proposal (because their anode refining department baghouse vents to the aisle scrubber), or if the EPA intends to retain the separate anode baghouse requirement.

Response: As described in section IV.B. of this preamble, we are promulgating a particulate emission limit for the combined stream of the anode refining department and the Hoboken converter process fugitive capture system (*i.e.*, aisle scrubber) as proposed in the 2023 supplemental proposal, as well as an independent anode refining department emission limit as proposed in the 2022 proposal. Compliance with the anode refining department emission limit will be demonstrated by complying with the appropriate limit, *i.e.*, if there is a combined emission stream then the affected source will comply with the combined emission standard, or if the anode refining department is independent (*i.e.*, not combined with other emission streams), then the affected source will comply with the independent limit for anode refining department.

d. What is the rationale for our final approach and final decisions for the anode refining point source revisions made pursuant to CAA section 112(d)(2) and (3)?

As discussed in the 2022 proposal preamble, the 1998 proposal for primary copper smelting major sources identified anode refining in the definition of primary copper smelters. However, at that time, the EPA did not have sufficient data to set an emission limit for anode refining, and therefore did not propose specific emission standards for anode refining operations in the major source NESHAP. The 2007 area source NESHAP includes emission standards for anode refining operations at area sources. Therefore, in the 2022 proposal, we concluded that anode refining is part of the source category and emits HAP emissions. In the 2022 proposal, we considered a BTF option, but did not consider going BTF in this case due to cost effectiveness. Pursuant to section 112(d)(2) and (3), we are finalizing, as proposed in the 2022 proposal, a MACT floor PM limit of 5.8 mg/dscm as a surrogate for metal HAP for new and existing anode refining departments. We are finalizing, as proposed, that compliance with the PM emissions limit for the anode refining department will be demonstrated through an initial performance test followed by a compliance test at least once per year. We are also finalizing to include the anode refining department as an emission source to be included in the alternative emission limit calculation for new facilities.

Based on the comments received on the 2022 proposal and the 2023 supplemental proposal and on information collected during a November 7, 2023, site visit to the Freeport facility, we are promulgating that compliance with the combined emission standard of 4.1 mg/dscm, for the combination of anode refining department emissions and Hoboken converter process fugitive capture system emissions (being promulgated under CAA section 112(d)(6) as described in section IV.B. of this preamble) will demonstrate compliance with the anode refining MACT floor PM limit. Under section 112(d)(6), we are finalizing initial and continuous compliance requirements for the combined emission standard including initial and subsequent annual performance testing. The combined standard and associated compliance requirements will ensure that affected sources can demonstrate compliance with the rule requirements.

2. Process Fugitive Emissions From Roofline Vents

a. What did we propose for process fugitive emissions from roofline vents pursuant to CAA section 112(d)(2) and (d)(3)?

As noted previously in the preamble for this final rule, the standards and associated compliance requirements for the process fugitive emissions from roofline vents source are being finalized pursuant CAA section 112(f)(2) to address unacceptable risk for the source category as well as pursuant to CAA section 112(d)(2) and (3). As proposed in the 2022 proposal and the 2023 supplemental proposal, we are promulgating the same emission standard to reduce risk to a level that would be considered acceptable and to satisfy the requirements of CAA section 112(d)(2) and (3). As discussed in the context of risk in section IV.A. of the preamble for this final rule, we proposed emission standards for the process fugitive emissions from roofline vents. In the 2022 proposal, we proposed separate standards for each roofline vent (*i.e.*, smelting vessels, copper converter department, and anode refining department) based on emissions data received from the Freeport facility. We performed a BTF analysis for additional controls of each roofline vent and concluded in the 2022 proposal that a BTF standard was appropriate for the anode refining process fugitive roofline vent while MACT floor standards were appropriate for the smelting and copper converter roofline vents.

During the comment period for the 2022 proposal, we received additional test data of the roofline vents from the Freeport facility. We received comments from both facilities in the major source category requesting that the roofline vent be a combined limit because there is comingling of emissions in the building where the processes are located. We received significant comment regarding the proposed test methods for demonstrating compliance with the roofline vent emission standards. We also received comments on our cost estimates for the BTF control option of the anode refining roofline vent.

In the 2023 supplemental proposal, we proposed a combined limit. The combined limit was calculated using the 99 percent UPL methodology. Specifically, for calculating the combined emission limit, we first determined the 99 percent UPL of the combined emission rates based on all test data now available for filterable PM. We then determined the average fraction of emissions which are attributable to the anode refining roof vent (72 percent). Then we adjusted the anode refining roof vent's portion of the 99 percent UPL by reducing that portion of the value by 90 percent. We also adjusted our costs in response to public comments on the proposed option to reflect the design requirements at the Freeport facility primarily by increasing the baghouse flowrate, lowering the air to cloth ratio and adding a lime injection system. The revised capital costs were $10.2 million and annualized costs were $2.14 million. The baghouse is expected to achieve 4.59 tpy reduction of lead and arsenic with a cost effectiveness of $467,000/ton metal HAP.

In addition, in the 2022 proposal we solicited comment on a lead limit for the roofline vents in addition to, or instead of, the PM limit for the anode refining roof vents. The agency considered a possible lead limit of 0.26 lb/hr as a potential BTF MACT limit for anode refining process fugitive emissions.

b. How did the requirements for process fugitive emissions from roofline vents proposed pursuant to CAA section 112(d)(2) and (3) change since proposal?

As discussed in this preamble, we are promulgating the combined BTF PM limit of 6.3 lb/hour for the roofline vents as proposed in the 2023 supplemental proposal. The BTF control cost estimates were updated to incorporate the most current bank prime interest rate resulting in a small increase in total annualized costs which are now estimated as $2.30 million with a resulting cost effectiveness of $500,000/ton metal HAP with 4.6 tpy (rounded from 4.59 tpy) reduction of lead and arsenic. The revised cost estimates are documented in the memorandum *Cost Estimates for Enhanced Capture and Control of Process Fugitive Emissions from the Anode Refining Operations at Freeport—REVISED*, which is available in the docket for this rulemaking. The cost estimates were otherwise unchanged and the adjustments do not change our conclusions about the necessity of promulgating the BTF standard. However, we received significant comment on the proposed compliance test methods. To address some of the concerns raised by the commenters, we are promulgating revised methods and allowing the use of Federal reference method (FRM) and Federal equivalent method (FEM) monitors as discussed in section IV.C.2.c.

We are promulgating a lead emission limit of 0.326 lb/hour for minimizing process fugitive emissions from any combination of roofline vents associated with the Peirce-Smith copper converter department, Inco flash furnace and the anode refining department, at existing sources. This emissions limit reflects the estimated reductions that will be achieved by the design standards described in section IV.B. We are also finalizing that facilities must demonstrate compliance with this emission limit once per year. We note that Peirce-Smith converters are batch converters and the NESHAP prohibits the use of batch converters for new sources. Therefore, this lead limit is not relevant for new sources.

c. What key comments did we receive on the proposed requirements for process fugitive emissions from roofline vents pursuant to CAA section 112(d)(2) and (3) and what are our responses?

Comment: Numerous comments were received on the proposed test methods for measuring PM at roof vents, which include EPA Test Methods 1, 2/2F/2G, 3/3A/3B, 4, 5D and Oregon Method 8. Most comments were that the proposed test methods are not suited for testing PM from roof vents; that MiniVol portable samplers should be used for sampling PM at the roof vents instead of the proposed test methods; and that the proposed test methods are unsafe to conduct at rooflines.

Commenters discussed the lack of isokinetic conditions at the roofline, which they stated inhibits the use of Method 1. For example, a commenter explained that Method 1 provides two alternative procedures: a ''simplified procedure,'' and an ''alternative procedure.'' Citing section 1.2 of the method, the commenter stated the simplified procedure ''cannot be used when the measurement site is less than 2 stack or duct diameters or less than a half diameter upstream from a flow disturbance.'' The commenter stated that neither stack diameters nor duct diameters can be defined for the smelter facilities' roofline vents, within the meaning and purposes of section 1.2. With regards to the alternative procedure, the commenter stated this procedure depends on the ability to develop representative pitch and yaw angles of the gas flow to be sampled, based on directional flow-sensing probe measurements of pitch and yaw angles at forty or more traverse points within the flow. The commenter stated this procedure is not possible to perform at the smelter facilities' roofline vents because fugitive emissions at the vents occur at a variety of angles that are constantly changing due to ambient winds.

Another commenter discussed the lack of isokinetic conditions at the roofline and referenced a feasibility study (EPA–HQ–OAR–2020–0430–0062) that concluded that the roofline vents at the Miami smelter cannot meet the minimum methods of Method 1, including either the simplified procedure or alternative procedure. The commenter stated that if Method 1 cannot be utilized effectively at the 2 facilities subject to the major source rule, the rule is not practical to implement or enforce.

A commenter discussed in depth the limitations of Method 5D, stating that, unlike a positive pressure baghouse for which Method 5D was designed, the roofline vent air flow is induced by natural buoyance of the warmer gas inside the smelter building and by outside air wind pressures—not by use of a forced air blower like those used in a baghouse. The commenter referenced an illustration in a technical analysis of the proposed vent test methods, which shows that the flow rate varies significantly over short periods of time and occasionally is negative (*i.e.*, air flows into the vent). Another commenter stated, ''FMMI identified the incompatibility of Method 5D to the roofline vent configurations as part of its original comments on April 26, 2022 . . . Nevertheless, the EPA left the issue unaddressed in the supplemental rule proposal, and the agency has not provided any guidance or technical analysis explaining how Method 5D could be adapted to the distinctly different conditions presented by the roofline vents.'' A commenter stated because EPA Method 5D is not compatible with the low, variable air velocities and physical configuration of the roofline vents, FMMI has utilized a sampling methodology and test protocol negotiated with the ADEQ (the ''ADEQ test method'').

Commenters advocated using MiniVol portable air samplers as an alternative to the proposed test methods for measuring PM from roof vents. They stated that using MiniVol portable air samplers is the most representative sampling method for the roofline emissions application, and while not a FRM sampler, they provide results that closely approximate data from FRM samplers to obtain representative concentrations of PM without the need for isokinetic sampling. The commenter noted that the portable air samplers can be run concurrently at several locations along the roofline, which the commenter notes offers several benefits: (1) fluctuations in flows and emissions along the roofline are better managed, (2) sampling is not dependent on linear air flow, so constant adjustments are not required, and (3) sampling can occur for longer periods of time, which provides a more representative sample of the process operations occurring in the smelter buildings. The commenter noted use of this sampling protocol will require the collection of velocity and temperature measurements using the existing roofline monitoring system equipment. As an added benefit, the portable air samplers also are capable of speciating samples of PM, PM_{10}, and $PM_{2.5}$.

A commenter noted that Asarco's 2015 consent decree with ADEQ, which governs the operation of their Hayden smelter, requires process fugitive emissions studies (FES) pursuant to a protocol (''FES Protocol'' or ''Protocol'') approved by the EPA on May 24, 2017. Within the FES Protocol is a determination that process fugitive PM emissions at the roofline shall be quantified via a sampling methodology that centers on the use of MiniVol portable air samplers at the roofline vents. The commenter stated that the EPA's approval of the Protocol constitutes a determination by the EPA that this sampling method is appropriate for determining the rate of fugitive PM emissions at the roofline. The MiniVol sampler, in particular, is a low-flow sampler, which is well-suited to low, variable air flows at the roofline—unlike the iso-kinetic sampling methods specified in paragraph (e)(1) of proposed 40 CFR 63.1450. The commenter attached copies of the Protocol and the EPA's approval of the Protocol to their comment letters submitted on the 2022 proposed RTR and on the 2023 supplemental proposal (Docket ID Nos. EPA–HQ–OAR–2020–0430–0135 and EPA–HQ–OAR–2020–0430–0204, respectively).

A commenter stated the final rulemaking should include a provision that explicitly authorizes the use of MiniVol portable air samplers, together with appropriate temperature and flow sensors to determine PM emissions at the roofline. The commenter advocated the use of a fugitive emissions monitoring protocol specific to the relevant smelter and approved by the EPA's Office of Air Quality Planning and Standards, Measurement Technology Group (MTG) or other reviewing body such as ADEQ and believes (a) 6 months after the date of the final rulemaking's publication in the **Federal Register** would be an appropriate deadline for submittal of the protocol for agency approval; and (b) 2 years after agency approval of the protocol would be an appropriate deadline for commencing measurements of the rate of fugitive PM emissions at the roofline to determine whether they exceed the fugitive PM emissions-rate limit. Correspondingly, the commenter noted the final rulemaking should provide that, during the pendency of the protocol's implementation, only the work practice standards and operation and maintenance requirements of the revised subpart QQQ rules shall apply to the process fugitive PM emissions. This would be consistent with 42 U.S.C. 7412(h)(1)–(2)(B) and the approach the EPA took in the Mercury and Air Toxics Standards (MATS) and Industrial Boilers rulemakings.

The commenter stated that the ADEQ test method was utilized to collect all of the emission data that the EPA relied on for the UPL calculation that is the sole basis for the combined roofline PM emission limit in the supplemental proposed rule. According to the commenter, it is not appropriate for the EPA to set emission limits based upon the ADEQ test method and then prohibit the use of that very same method to demonstrate compliance. If the ADEQ test method was good enough to set enforceable emission limits, it should also be good enough to demonstrate compliance. The commenter stated that if the ADEQ test method (or some reasonable modification of that method) does not meet the EPA's requirements, then no limit should be established at this time because that approach necessarily means that a valid data basis for a limit does not yet exist. If that is indeed the EPA's position FMMI and the EPA can work together to develop an acceptable test method, FMMI can collect the necessary data to support the calculation of a UPL based on that agreed method, and the agency can set emission limits based on that data set.

In a related point, a commenter stated that they are concerned that the proposed roofline lead limit is based on data collected using samplers that are not designated as an FRM. Use of non-FRM sampler data could create a standard that is not achievable if tested using an FRM. It is unclear from the EPA's proposed rule how to address a potential discrepancy between a standard based on non-FRM and testing using an FRM. The commenter goes on to say that the EPA's proposed PM limit was established using data that were collected using a method other than EPA Method 5. Another commenter has similar concerns with the EPA's rule in regard to the proposed limit being based on data collected using samplers that are not designated as an FRM: First, they state it is not clear from the EPA's rule that a Method 5 test conducted at the same time would have produced the same result as the alternative method used to obtain the data the rule is based on. Second, they state it is unknown whether this standard is achievable, as determined by the proposed test methodology.

Lastly, commenters had concerns about the safety of the personnel conducting testing at the roofline. The commenter stated it would be unsafe, due to the elevated temperature environment and other conditions at the roofline, for humans to perform roofline activities required by paragraph (e) of proposed 40 CFR 63.1450. Many areas of the roofline are currently only accessible by narrow catwalks that do not currently have approved tie-off points or sufficient space to accommodate the personnel and the required sampling equipment. Some roofline areas require respirators or other personal protective equipment, and the EPA's proposed testing methods would require continuous presence of multiple personnel working directly in the pathway of exiting fumes for 3, 12-hour test runs. The commenter stated the Method 5 sampling protocol requires adequate sample locations to account for variations in the flows along the roofline, which then necessitates a large number of sampling staff to be located in a dangerous, high temperature environment for extended periods of 12 hours or more. The commenter noted the temperatures at the roofline can reach 140 degrees Fahrenheit and pose a significant safety concern for the testing personnel.

Response: In reviewing the comments and as a result of a site visit, the EPA is revising the methods for the roof-vent testing. For sample location determination, if EPA method 1 is inappropriate, the facilities need to use method 5D, section 8.1.3, Roof Monitor or Monovent, and also use section 8.2 to determine how many traverse points should be sampled or have proposed sampling locations approved by EPA Office of Air and Radiation (OAR), Office of Air Quality Planning and Standards, MTG or the delegated authority. Due to the variability in the flow rates, an anemometer may be used to determine the flow. For the PM concentration measurements, a constant sample flow rate and mass volume is required due to the highly variable process flow rate. EPA method 17 may be used for this constant flow rate sampling. EPA Method 17 particulate matter samples will be collected at the roofline vent temperatures to maintain the same temperature basis as the samples used in setting the standard. EPA Methods 5 and 5D have been removed since these methods require heating the filter to 248 ± 25 Fahrenheit, which would not be representative of the roofline temperatures. It is understood that isokinetics may not be met with this sampling and this calculation is waived for this sampling.

The MiniVol samplers are not EPA-approved samplers. There is a concern because these are battery operated and may not provide a constant rate of sampling. As an alternative, an approved FRM or FEM ambient PM monitor may be used, which will also address the commenter's safety concerns. A list of designated reference and equivalent methods is provided here: *https://www.epa.gov/amtic/air-monitoring-methods-criteria-pollutants*. However, tapered oscillating microbalances are not appropriate for this sampling. The FRM or FEM ambient PM monitor must be able to tolerate temperatures up to 150 degrees Fahrenheit.

The commenter has raised concerns on the use of the MiniVol sampler to set the standard while different methods are used for determining compliance. The EPA has mitigated these issues through the adaptations to the methodology finalized, the use of calibrated anemometer for low and variable process flow rates, fixed rate sampling and the allowance for in stack filter methodology (EPA Method 17). The primary sampling difference between the methods now is the more stable operation of the EPA Method 17 sampling system or an FRM/FEM, ensuring that the sampled flow rate is consistent.

The EPA alternative methods approval is conducted by the Measurement Technology Group (MTG). The MiniVol roof-vent sampling protocols/sampling methods have not been submitted or approved by MTG. The Asarco protocol included FRM sampling side-by-side with the MiniVol sampling. This side-by-side sampling could use Method 301 to validate the MiniVol samplers, but the proposed sampling has not yet occurred. This Method 301 validation could still occur, and the data could be used to support an alternative method approval from MTG. If these revised methods are not appropriate or the tester/facility wants to use alternative methods, the tester/facility can apply for an alternative test method approval through MTG. A Method 301 study should be conducted to verify that the selected monitors used provide equivalent data to the EPA methods.

Comment: A commenter agreed with the EPA's reasoning and determination not to propose a BTF lead emissions limit in addition to, or instead of, the fugitive PM emissions limit in proposed 40 CFR 63.1444(i)(3). Similarly, another commenter stated that, in response to EPA's request for comments, an additional lead limit on the roofline vents is not necessary. They explained that they agreed with the EPA's conclusion that PM is the most appropriate surrogate for metal HAPs.

Response: While we agree that PM is an appropriate surrogate for metal HAP, we are also finalizing a process fugitive lead limit for facilities using flash furnaces and associated with the Peirce-Smith converters of 0.326 lb/hr for a combination of roof vents associated with Peirce-Smith copper converter department, Inco flash furnace and the anode refining department. We estimate that this final standard will reduce lead emissions by 0.39 tpy.

Comment: Commenters requested that the EPA establish direct lead limits, either in addition to or instead of the PM limit because it is one of the risk drivers for this source category and would be appropriate to control for it directly.

Response: We have determined that filterable particulate is an adequate surrogate for lead and other HAP metals for this source category. The use of PM as a surrogate for particulate metal HAP is consistent with the approach used to limit particulate metal HAP emissions from other copper smelting processes in the current NESHAP and for many other source categories (i.e., Ferroalloys Production, Integrated Iron and Steel Manufacturing, and Integrated Iron and Steel Foundries). Therefore, providing PM emission standards which require reductions as a surrogate for metal HAPs is expected to result in commensurate reductions of metal HAP. We are also finalizing a process fugitive lead limit for facilities using Inco flash furnaces and Peirce-Smith converters of 0.326 lb/hr for a combination of roof vents associated with the Peirce-Smith copper converter department, Inco flash furnace and the anode refining department which we estimate will reduce lead emissions by 0.39 tpy.

d. What is the rationale for our final approach and final decisions for the process fugitive emissions from roofline vents revisions made pursuant to CAA section 112(d)(2) and (3)?

As described in the 2022 proposal and in the 2023 supplemental proposal, the 2002 major source NESHAP does not include standards for process fugitive emissions from the rooflines of smelting vessels, converters, or anode refining operations, except for an opacity limit for converter roof vents that applies during testing. Therefore, we are finalizing, as proposed in the 2023 supplemental proposal, a BTF combined PM limit of 6.3 lb/hr as a surrogate for metal HAP for new and existing process fugitive emissions from roofline vents pursuant to CAA section 112(d)(2) and (3). As described in section IV.A., we are also finalizing this combined roofline PM limit under CAA section 112(f) to reduce emissions of HAP metals (especially lead and arsenic, which are two persistent, bioaccumulative and highly toxic HAPs), and their associated risks, to achieve acceptable risks levels. We are finalizing, as proposed, that compliance with the PM emissions limit for the process fugitive emissions from roofline vents will be demonstrated through an initial performance test followed by a compliance test at least once per year. Based on comments we received on the 2022 proposal and the 2023 supplemental proposal, we are finalizing adaptations to the test methods by which compliance with this limit can be demonstrated including the use of fixed rate sampling and the allowance for in stack filter methodology (EPA Method 17). The costs for Freeport to comply with this combined PM limit are described in section IV.C.2.b., and we estimate that Asarco can already comply with this limit and therefore will not incur costs to comply with the combine PM roofline limit except testing costs. We estimate that both facilities will incur testing costs of $107,000 per year to comply with the performance test requirements.

In addition, we are finalizing a lead emission limit of 0.326 lb/hour to minimize process fugitive lead emissions from any combination of roofline vents associated with Peirce-Smith copper converter departments, Inco flash furnaces and the anode refining departments, at existing sources. This limit will only apply to the Asarco facility (since they are the only existing major source with Peirce-Smith copper converter departments and Inco flash furnaces), and we estimate this will reduce metal HAP by 0.39 tpy and ensure that future violations of the lead NAAQS will not occur. As mentioned in section IV.B.2. of this preamble, Asarco has been a major contributer to the Hayden Arizona lead NAAQS non-attainment status. This limit is consistent with the modeling demonstration submitted by the facility to the state in support of a revision to the lead SIP. This document is available in the docket for this action (Docket ID No. EPA–HQ–OAQ–2020–0430). As discussed in section IV.B., we are also promulgating design standards under CAA section 112 (d)(6) that will ensure this limit is met. As discussed in section IV.B., the costs to comply with the design standards are already expected to be incurred by the facility. We are finalizing, that compliance with the lead emissions limit for the process fugitive emissions from roofline vents will be demonstrated through an initial performance test followed by a compliance test at least once per year. The facility can test for lead at the same time as the performance test for PM; however, they will have some additional costs for the laboratory analysis that we estimate to be $18,000 per year.

3. Mercury

a. What did we propose for mercury emissions pursuant to CAA section 112(d)(2) and (3)?

In the 2022 proposal, the EPA proposed a BTF mercury limit of 0.0043 lb/hr for existing sources, based on emissions data from Freeport and Asarco, and a MACT floor mercury limit of 0.00097 lb/hr for new sources, based on emissions data from Asarco. As noted in the preamble of the 2022 proposal, in order to comply with the proposed emission limit for existing sources, the EPA expected that the Freeport facility would have to install and operate an activated carbon injection (ACI) system and a polishing baghouse on the stack emissions release point, the acid plant. The EPA expected the installation of these additional controls would result in a 90 percent reduction of mercury emissions from the acid plant source and that the cost-effectiveness of mercury control would be $27,500 per pound (in 2019 dollars).

During and after public comment period of the 2022 proposal, the EPA received a number of comments and additional data concerning the BTF limit for existing sources including:

- Mercury testing results obtained in 2018–2021 by the Freeport facility which did not fully follow EPA Method 29;
- Additional mercury testing results collected at the Freeport facility in 2022 which fully followed EPA Method 29; and
- Comments regarding the technical infeasibility of adding mercury controls (e.g., polishing baghouse with ACI) at the acid plant, including explanations that the conditions of the acid plant exhaust streams are unsuited for the control option since the stream has a high moisture content, low mercury concentrations, and high concentrations of SO_2/SO_3 which inhibit mercury removal.

As discussed in the 2023 supplemental proposal, the EPA evaluated the emissions data from all of Freeport's performance tests (*i.e.*, 2018–2022) and concluded that only the test conducted in 2022 which fully followed Method 29 should be used in the MACT floor emission limit development. The EPA also agreed that characteristics of the exhaust stream from the acid plant stack and equipment configuration at the acid plant may inhibit mercury control (*e.g.*, moisture content, acid gas content, mercury concentration) which could result in diminished emission reductions. Therefore, we evaluated controlling mercury from the aisle scrubber stack and the vent fume stack and determined the latter was best suited for mercury control (see discussion in the 2023 supplemental proposal). Based on a new stack location and a new emissions data set, which includes the original Asarco data and data from Freeport's 2022 test, the revised mercury limit for existing sources in the 2023 supplemental proposal, as determined using the 99 percent UPL approach, is a MACT floor limit of 0.033 lb/hr for combined facility wide emissions. We also evaluated BTF control options in the 2023 supplemental proposal and concluded that the costs were unreasonable, and we proposed the MACT floor emission standard. We proposed that compliance with the mercury emissions limit for new and existing sources would be demonstrated through an initial compliance test for each of the affected sources (*e.g.*, furnaces, converters, anode refining) followed by a compliance test at least once every year.

b. How did the mercury emissions standard made pursuant to CAA section 112(d)(2) and (3) change since proposal?

The mercury emission standard for new sources, 0.00097 lb/hr, is being promulgated as proposed in 2022. In the 2023 supplemental proposal, we proposed a revised mercury emission standard of 0.033 lb/hr for existing sources and are finalizing that standard as proposed. Both emission standards are based on the MACT floor.

c. What key comments did we receive on the mercury revisions made pursuant to CAA section 112(d)(2) and (3) and what are our responses?

Comment: Commenters contend that the EPA does not have sufficient data to develop a MACT floor for mercury. They stated that they do not believe the single 3-run test results are sufficient to establish the proposed MACT floor emission standard for existing sources. The commenter noted there was significant run-to-run variability which the commenter stated can be attributed to the profile of the process feed and the nature of a batch process. Commenters noted that additional performance testing of mercury will be conducted at the Freeport facility in the fourth quarter of 2023, and first quarter of 2024 using EPA Method 29, and they asked that the EPA allow for submittal and consideration of these data (which they say they will be able to provide at least several weeks prior to the May 2, 2024, deadline for final rule publication) when establishing limits in the final rule. In the absence of additional data, commenters believe that a representative MACT floor cannot be established, and any regulatory action should be postponed or limited to workplace standards. They rationalized this comment by citing the NESHAP for Secondary Lead Smelting (77 FR 570) where the EPA did not promulgate standards because of incomplete testing and lack of testing data for furnaces that burn varying types of fuel.

Response: As described in the 2023 supplemental proposal, the EPA revised its calculations by only using the stack test data that followed EPA Method 29. The proposed mercury standard was developed based on the 99 percent UPL of the available emissions data for this source category, which included data collected from Freeport through the 2022 section 114 information request from Freeport as well as test data from Asarco, yielding a sample size of 5 data points. The test report associated with Freeport's section 114 information request response was conducted using EPA test Method 29 and was reviewed by EPA measurement experts upon submission. A dataset of more than 3 data points meets the sample size necessary to use the 99 percent UPL approach to develop a MACT standard. We acknowledge that a sample size of 5 is considered a limited dataset; however, we have followed our documented approach for MACT floor development for limited datasets included in Appendix B of the aforementioned memorandum (Docket ID No. EPA–HQ–OAR–2020–0430–0153). Therefore, we disagree that we have insufficient data to develop a numerical emission standard based on the MACT floor.

We note that we received two additional test reports from Freeport; one on January 29, 2024 (non-metal HAPs) and one on February 16, 2024 (mercury), well after close of the public comment period (*i.e.*, September 22, 2023) and have been notified that Freeport plans to send a third test report in mid-April 2024. Based on a preliminary review of the new test data, we determined that some tests were not valid due to deviation from the EPA method and that incorporation of the valid tests would not result in significant changes to the proposed emission limits. We did not incorporate these late-submitted data for two timing related reasons. First, other stakeholders would not have an opportunity to review and comment on these new data; and second, given the court-ordered promulgation deadline of May 2, 2024, we had insufficient time to complete the necessary quality control and assurance of the data, and to perform new calculations and analyses to establish revised limits before the May 2, 2024, deadline. Thus, we are promulgating the existing source MACT floor emission standards for mercury, as well as for the other non-metal HAP, as proposed in the 2023 supplemental proposal and as discussed in sections IV.C.3. and IV.C.4. of this preamble.

Comment: Some commenters expressed support for the decision in the 2023 supplemental proposal not to move forward with a BTF standard for mercury, while other commenters suggested that the EPA adopt the BTF standard for mercury. Commenters stated that indirect costs including engineering, procurement, and construction management, as well as startup costs had not been included in our estimates. Specifically concerning costs for baghouses, commenters stated that most modern baghouses are of the pulse jet, rather than shaker style, configuration.

Response: As described in the 2023 supplemental proposal, the EPA re-proposed a MACT floor standard for mercury after considering the technical feasibility and costs of BTF control options. In consideration of the comments regarding costs, we performed a holistic review of the cost estimates for controls included in this rulemaking. As described in the 2023 supplemental proposal, we estimated costs for controlling mercury at the vent fume stack using a polishing baghouse with ACI. We found that our BTF cost estimates for mercury controls omitted indirect costs and assumed costs for a shaker style baghouse. In response to the comments received on the 2023 supplemental proposal, we have revised our BTF cost estimates for mercury control of the vent fume stack at the Freeport facility to include indirect costs and to more appropriately assume a pulse jet configuration baghouse. The details of these revisions can be found in the memorandum *Estimated Cost for Beyond-the-floor Controls for Mercury Emissions from Primary Copper Smelting Facilities—REVISED*, available in the docket for this rulemaking. Our revised estimates of the cost of BTF mercury are capital costs of $10.7 million and total annualized costs of $3.0 million. We did not receive additional test data or other information that would result in revisions to the expected emission reductions we presented in the 2023 supplemental proposal. Using the expected reductions, 40.5 lb/yr, the resulting cost effectiveness is $73,300/lb mercury. We continue to maintain, as proposed in the 2023 supplemental proposal, that the cost effectiveness for the BTF control of mercury is unreasonable and are promulgating the MACT floor emission standard for existing sources.

d. What is the rationale for our final approach and final decisions for the mercury revisions made pursuant to CAA section 112(d)(2) and (3)?

As described in the 2022 proposal and the 2023 supplemental proposal, the 2002 major source NESHAP does not include standards for mercury. We are finalizing, as proposed in the 2022 proposal, the new source MACT floor mercury limit of 0.00097 lb/hr mercury. As stated in the 2022 proposal, the new source MACT floor mercury limit was calculated based on emissions data from the best performing facility, which is Asarco in this case. We are finalizing, as proposed in the 2023 supplemental proposal, the existing source MACT floor mercury limit of 0.033 lb/hr mercury. As discussed in section IV.C.3.c. of this preamble, we made some revisions to the cost of mercury controls that were included in the 2023 supplemental proposal. These revisions improved the completeness of our estimates but did not change our conclusion that the costs of the BTF option for controlling mercury with a polishing baghouse and ACI at the vent fume stack are unreasonable ($73,000/lb mercury reduced). We also considered other BTF options, but all other options were less cost-effective than additional controls of the vent fume stack using the baghouse/ACI option. We note the BTF options we considered are higher than historic acceptable cost effectiveness values for mercury. The highest historic acceptable cost-effective values in the 2011 final MATS rule were up to $22,400 per pound of mercury reduced in 2007 dollars (which equates to about $32,000 per pound in current dollars). We are finalizing, as proposed, that compliance with the mercury emissions limit for new and existing sources will be demonstrated through an initial compliance test for each of the affected sources (*e.g.,* furnaces, converters, anode refining) followed by a compliance test at least once every year.

4. Other Unregulated HAP

a. What did we propose for the unregulated HAP pursuant to CAA section 112(d)(2) and (d)(3)?

During the public comment period of the 2022 proposal, the EPA received comments claiming there were additional unregulated HAP from the source category beyond those we addressed in the 2022 proposal. In response to these public comments, the EPA issued a CAA section 114 information request to collect further information. The information request was sent to the Freeport facility only, as the Asarco facility has been idled since October 2019. The collected data indicated the following additional unregulated pollutants are emitted from the source category: benzene, D/F, HCl, chlorine, PAH (including naphthalene), and toluene. These pollutants are mainly emitted due to the combustion of natural gas and coke. Based on this new information, the EPA proposed the following MACT floor emission limits for these pollutants in the 2023 supplemental proposal:

- 1.7E–03 lbs benzene/ton concentrated ore fed for new and existing sources;
- 8.4E–04 lbs toluene/ton concentrated ore fed for new and existing sources;
- 1.5E–03 lb/ton concentrated ore fed for HCl for new and existing sources;
- 5.4E–03 lbs chlorine/ton concentrated ore fed for new and existing sources;
- 1.0E–04 lbs PAH excluding naphthalene/ton concentrated ore fed for new and existing sources;
- 2.8E–04 lbs naphthalene/ton concentrated ore fed for new and existing sources; and
- 60 ng D/F TEQ/Mg concentrated ore fed for new and existing sources.

We also proposed that compliance with the unregulated HAP emissions limits for each affected source will be demonstrated through an initial performance test followed by a compliance test at least once every 5 years.

b. How did the unregulated HAP revisions made pursuant to CAA section 112(d)(2) and (3) change since proposal?

As described in section IV.C.4.a., we proposed MACT floor emission limits for benzene, D/F, HCl, chlorine, PAH (including naphthalene), and toluene. The decision not to propose BTF emission limits was based on the results of our BTF analysis. The BTF analysis assumed ACI or DSI would be installed with an existing scrubber to achieve the expected emission reductions. However, based on comments received on this analysis as discussed in section IV.C.4.c. of this preamble and the promulgation of additional controls for the Hoboken converter process fugitive capture system, we made revisions to our BTF analysis. Specifically, we revised the BTF control options to be the addition of ACI or DSI to the baghouse control device we expect will be installed upstream of the aisle scrubber to control the Hoboken converter process fugitive capture system, rather than a scrubber. We revised the expected emission reductions for each unregulated HAP (i.e., benzene, D/F, HCl, chlorine, PAH (including naphthalene), and toluene) to reflect the assumption that the baghouse will receive about 75 percent of the loading to the aisle scrubber. The performance test results that were used to quantify emission reductions of the unregulated HAP were conducted at the outlet of the aisle scrubber. Therefore, we are revising the emission reduction estimates provided in the 2023 supplemental proposal to be based on the expected loading to the baghouse. We did not identify any BTF options for HCl because the MACT floor emission standard was set at 3 times the representative detection limit (3xRDL) and it is infeasible to measure lower levels of this pollutant. For Cl, we adjusted our expected emission reductions from the addition of DSI based on an expected control efficiency of 98 percent to 20 percent. This control efficiency adjustment was in response to a comment we received from Freeport. Freeport commented that the stack test data was taken from the aisle scrubber outlet; because the aisle scrubber is a caustic scrubber additional reduction of acid gases would be expected to be far lower than our proposed 98 percent. They estimated it should be 0 to 20 percent. We agree and thus updated the expected control efficiency to 20 percent. Finally, as noted previously in this preamble, during the comment period for the 2023 supplemental proposal, we received comments on control costs and performed a holistic review of all control cost estimates for this rulemaking. These comments stated that installation costs and indirect costs including engineering, procurement, and construction management, as well as startup costs and contingency had not been included in our estimates. We also received comments regarding the sizing of a DSI system for the baghouse for the Hoboken converter process fugitive capture system as discussed in section IV.B. The costs for ACI and DSI were updated to include installation and indirect costs including contingency for completeness and were updated in response to comments regarding the sizing of such systems for the baghouse expected to be required for controlling the Hoboken converter process fugitive capture system. Based on these revisions, the quantity of expected emission reductions from the addition of DSI or ACI was reduced, and the overall cost effectiveness increased for unregulated HAP. This did not change our proposal to base numerical emission standards for these pollutants on the MACT floor. The detailed emission reductions and cost estimates for the revised BTF options for this final rule are provided in a memorandum entitled *Estimated Cost for Beyond-the-floor Controls for Unregulated HAP Emissions from Primary Copper Smelting Facilities—REVISED,* which is available in the docket for this action. Units of unregulated HAP were also revised from pounds (or nanograms) per ton (or Mg) concentrated ore fed, as applicable, to pounds (or nanograms) per ton (or Mg) of copper concentrate feed charged to the smelting vessel.

c. What key comments did we receive on the unregulated HAP revisions made pursuant to CAA section 112(d)(2) and (3) and what are our responses?

Comment: Commenters appreciated that the EPA proposed MACT standards for the unregulated pollutants, but they also encouraged the EPA to reconsider the BTF options for control of these pollutants and require the additional control requirements. Commenters questioned the approach used to evaluate the BTF cost of controls for the nonregulated pollutants. By taking a pollutant-by-pollutant approach to assessing the cost per ton of pollution, the EPA's approach makes the cost assessment very high. For example, the BTF control options for benzene, PAH, naphthalene, and D/F were all estimated with the addition of ACI to the existing control device. So, the capital outlay and operational cost should include the tons per year (tpy) reduction of all pollutants instead of looking at the cost per ton for each one individually. Similarly, the BTF control for HCl and Cl is DSI, so one control will address both pollutants.

Response: We conclude that even by evaluating the combination of pollutants noted by the commenter, we would still consider the costs of complying with the BTF standards for these HAP not reasonable in this case. Generally, we find that the annualized emissions of these unregulated HAP are quite low, and our BTF analysis which informed the 2023 supplemental proposal concluded that the costs and cost-effectiveness associated with the BTF options were not reasonable. For more details on the BTF analysis, see the memorandum entitled *Estimated Cost for Beyond-the-floor Controls for HAP Emissions from Primary Copper Smelting Facilities—REVISED,* which is available in the docket for this action.

Comment: Commenters stated the proposed MACT standards for the unregulated HAP are inappropriate because they would apply to both the Freeport facility and the Asarco facility when they are based on emissions data and information collected exclusively from the Freeport facility, and unique to Freeport's use of fuels and other raw materials which are precursors to such HAP emissions from the Freeport facility. Commenters stated that promulgation of the MACT standards would, therefore, violate 42 U.S.C. 7412(d)(3)(B) for failing to be based empirically or predictively on HAP emissions data and information pertaining also to the Asarco facility. Commenters stated the EPA should engage with Asarco to determine whether the facility has relevant HAP emissions data for consideration in the rulemaking, or not set standards for HCl, Cl or D/F because: (1) the overall emissions profiles of these HAP would be particularly sensitive to variations in feed to the smelter, including changes in quantities and qualities of fuel and additives, such as coke, flux and scrap; and (2) the individual stack emissions profiles of these HAP—including distributions and emissions rates—would vary greatly between the point sources at the Freeport facility and the point sources at the Asarco facility, due to the substantial differences between the process flows and gas flows (including capture) at the Freeport facility and the process flows and gas flows (including capture) at the Asarco facility. Commenters also contended that the MACT standards for unregulated HAP are based on a single testing campaign; therefore, a representative MACT floor cannot be established. Commenters noted that additional performance testing of the unregulated HAP will be conducted at the Freeport facility in the fourth quarter of 2023 and first quarter of 2024, and they asked that the EPA allow for submittal and consideration of these data (which they said they will be able to provide at least several weeks prior to the May 4, 2024, deadline for final rule publication) when establishing limits in the final rule. In the absence of additional data, commenters believe that a representative MACT floor cannot be established, and any regulatory action should be postponed or limited to workplace standards.

Response: The proposed unregulated HAP standards were developed based on the 99 percent UPL of the available emissions data for this source category, which included data collected through the 2022 section 114 information request to Freeport. The testing associated with Freeport's section 114 information request response was conducted using the EPA prescribed test methods, and the results were reviewed by EPA measurement experts upon submission. We did not find equivalent data from Asarco in the administrative record. Nevertheless, the EPA is allowed to and required to establish MACT standards for a source category based on sources for which we have emissions data; thus, the data for Freeport must be used for the source category in the absence of data from Asarco. The 3 data points we used to set the floor are the minimum sample size necessary to use the 99 percent UPL approach to develop a MACT standard. While we acknowledge this is a limited dataset, we followed the EPA protocol for developing MACT from limited datasets which was described in Appendix B of the *Proposed Maximum Achievable Control Technology (MACT) Floor Analysis for Unregulated HAP for the Primary Copper Smelting Major Source Category* memorandum (Docket ID No. EPA–HQ–OAR–2020–0430–0153); therefore, we disagree that we have insufficient data to develop numerical emission standards based on the MACT floor.

As described in section IV.C.3.c. of this preamble, we note that we received an additional test report for these non-metal HAPs on January 29, 2024, well after close of the public comment period (i.e., September 22, 2023). However, for the reasons described in section IV.C.3.c., we did not incorporate these new data in our analyses to establish revised standards for the final rule. Therefore, we are promulgating the MACT floor emission standards for these unregulated HAP, as proposed.

Comment: Commenters agreed with the EPA's conclusion that the BTF options for controlling unregulated HAP are not cost effective. They also noted these control options, which include the use of ACI and DSI in combination with the aisle scrubber, are not technically feasible. Commenters noted that the aisle scrubber is a wet scrubber designed for acid gas control, and the use of either ACI or DSI would require a high-efficiency particulate control device such as a baghouse to collect the injected material. The commenter stated that the addition of a baghouse would significantly increase control costs for the pollutants, making the cost effectiveness of their control poorer. With regards to HCl and Cl, commenters stated the EPA's estimated emissions reductions of 98 percent for these pollutants using DSI injection is not practical given their already efficient removal by the aisle scrubber and thus already very low stack concentrations. DSI could not be expected to reduce emissions of these pollutants by more than 20 percent and could potentially result in 0 percent emission reduction.

Response: As described elsewhere in this preamble, we are promulgating a combined emission standard for the combination of exhaust streams from the anode refining department and the Hoboken converter process fugitive capture system. At the Freeport facility, the anode refining department and the Hoboken converter process fugitive capture system exhaust streams combine in the aisle scrubber from which they are emitted to the atmosphere. The Freeport facility controls the anode refining department emissions with a baghouse prior to routing the exhaust to the aisle scrubber. We expect that the combined standard we are promulgating in this action will require the installation of a baghouse to control the emissions stream from the Hoboken converter process fugitive capture system. Therefore, the costs for a primary particulate control device of the emission streams which combine in the aisle scrubber will be incurred to comply with the combined emission standard. As discussed in section IV.C.4.b., in response to comments for this rulemaking we are amending our cost estimates included in the 2023 supplemental proposal for controlling these unregulated HAP to include installation and indirect costs including contingency as well as to address comments regarding the sizing of these injection systems. We continue to expect that DSI/ACI systems would be required to provide control for these pollutants, and, thus, our revised estimates continue to represent the incremental costs of adding these systems to an existing control device, which will now be the baghouse required for compliance with other requirements in this final rulemaking. As noted in our previous discussion of the baghouse for the Hoboken converter process fugitive capture system, the baghouse receives about 75 percent of the loading to the aisle scrubber. The performance test results which were used to inform the emission standards and to quantify emission reductions of the unregulated HAP (*i.e.,* benzene, D/F, HCl, chlorine, PAH (including naphthalene), and toluene) were conducted at the outlet of the aisle scrubber. Therefore, we are revising our emission reduction estimates provided in the 2023 supplemental proposal to be based on the expected loading to the baghouse (*i.e.,* 75 percent of the emission rates from the aisle scrubber outlet). Concerning the control efficiency applied to HCl and Cl emissions, we note that the measurements of emission rates were taken at the outlet of the aisle scrubber. The aisle scrubber is designed to reduce acid gases including HCl and Cl; therefore, we agree with commenters that assuming an additional 98 percent reduction of the emission rates at the aisle scrubber in our BTF evaluation is likely technically infeasible. In reviewing the data for HCl, we note that the 99 percent UPL was less than 3 times the representative detection limit (3xRDL), thus the emission standard was set at 3xRDL consistent with EPA emission standard development procedures. Therefore, it is infeasible to measure lower levels of HCl and we are no longer considering BTF options for this pollutant. However, we have revised our estimated emission reductions for Cl to assume a 20 percent reduction. The revisions to the expected quantity of emission reductions and our cost estimates result in increased cost effectiveness for these unregulated HAP. For chlorine, benzene, toluene, and PAH, the cost effectiveness ranges from $8.1 million/ton HAP reduced to $120 million/ton of HAP reduced. For D/F, the cost effectiveness is $107 million/gram of HAP reduced. These revisions do not change our conclusion that the BTF costs for controlling these pollutants are unreasonable, and we are therefore promulgating the MACT floor standards. The details of our BTF analysis can be found in *Estimated Cost for Beyond-the-floor Controls for HAP Emissions from Primary Copper Smelting Facilities—REVISED,* which is available in the docket for this rulemaking.

Comment: Commenters noted that the proposed standards for unregulated HAP are a function of concentrated ore fed, i.e., the emission limits are pounds per ton concentrated ore fed. Commenters stated that some of these compounds are not correlated with ore composition, but instead with natural gas consumption or impurities from third party copper scrap recycling. The commenters noted that additional performance testing should be conducted to inform whether other operating parameters influence emissions.

Response: We used production-based thresholds to provide equitable emission standards for other facilities in the source category. No data was provided by FMMI indicating whether copper scrap was part of the feed during the performance tests which informed the emission standards. However, in light of the possibility that copper scrap was part of the feed during the tests conducted in response to the 2022 section 114 information request, we are changing the denominator from a concentrated ore fed basis to a copper concentrate feed charged to the smelting vessel basis, where ''copper concentrate feed'' is defined in 40 CFR 63.1459.

d. What is the rationale for our final approach and final decisions for the unregulated HAP revisions made pursuant to CAA section 112(d)(2) and (3)?

As discussed in the 2023 supplemental proposal, the EPA identified benzene, toluene, HCl, Cl, PAHs, and D/F in the major source category for which the 2002 major source NESHAP did not include standards. Except for HCl, the standards we are promulgating for unregulated HAP are MACT floor limits based on the 99 percent UPL. For HCl, the 99 percent UPL was less than 3xRDL for HCl, therefore, consistent with EPA guidelines, the latter was used to set the MACT floor limit. As discussed in the 2023 supplemental proposal, the EPA evaluated BTF limits for each pollutant but did not propose them due to unreasonable costs. Therefore, consistent with the 2023 supplemental proposal, we are promulgating numerical emission standards for each unregulated HAP *(i.e.,* benzene, D/F, HCl, chlorine, PAH excluding naphthalene, naphthalene, and toluene). We are also promulgating, as proposed, that compliance with these standards will be demonstrated by an initial performance test and subsequent performance testing at least once every 5 years.

5. New Copper Converter Departments

a. What did we propose for the new copper converter departments pursuant to CAA section 112(d)(2) and (d)(3)?

The EPA proposed in the 2022 proposal a MACT floor limit for new copper converters of 0.031 lbs of PM$_{10}$ per ton of copper concentrate feed charged to the smelting vessel. We also proposed that compliance with the PM$_{10}$ emissions limit for new copper converter departments will be demonstrated through an initial performance test followed by compliance test at least once per year.

b. How did the new copper converter departments revisions made pursuant to CAA section 112(d)(2) and (3) change since proposal?

The proposed limit and compliance requirements were not changed.

c. What key comments did we receive on the proposed new copper converter departments revisions made pursuant to CAA section 112(d)(2) and (3) and what are our responses?

The EPA did not receive notable comments on the proposed limit or proposed compliance requirements.

d. What is the rationale for our final approach and final decisions for the new copper converter departments revisions made pursuant to CAA section 112(d)(2) and (3)?

As discussed in the 2022 proposal, the 2002 major source NESHAP current requirement for new converters is that the use of new batch copper converters is prohibited. Any new copper converters covered by the major source NESHAP would need to be continuous converters or some other currently unknown non-batch converter technology. However, the 2002 major NESHAP did not include an emissions standard for new converters. Therefore, pursuant to CAA section 112(d)(2) and (3), the EPA is finalizing, as proposed in the 2022 proposal, the MACT floor limit for new copper converters of 0.031 lbs of PM$_{10}$ per ton of copper concentrate feed charged to the smelting vessel and related compliance requirements. As discussed in the 2022 proposal, there are currently no existing continuous converters in the major source category, and therefore, we did not propose and are not finalizing an emission standard for existing continuous copper converters. Also as discussed in the 2022 proposal, since there are no existing continuous copper converters in the major source category, the PM$_{10}$ limit is based on the performance of the best similar source, which is the Kennecott primary copper smelting facility. We did not identify any cost-effective BTF options.

D. Final Rule Amendments Addressing Bypass Stack Emissions

1. What revisions did we propose for bypass stack emissions?

We proposed in the 2023 supplemental proposal prohibiting the use of a bypass stack. We also proposed in the 2023 supplemental proposal a definition of ''bypass stack'' in 40 CFR 63.1459 and proposed that use of a bypass stack will result in a violation of the numerical emission standards contained in the Primary Copper Smelting NESHAP in 40 CFR 63.1444. We proposed that the use of a bypass stack during a performance test will invalidate the test.

2. How did the bypass stack revisions change since proposal?

Based on consideration of comments, the EPA is not prohibiting the use of a by-pass stack. Instead, EPA is promulgating a work practice standard pursuant to CAA section 112(h) to minimize HAP emissions vented through a bypass stack during planned maintenance events. We are promulgating work practices instead of an emissions limit because we determined it is not economically or technically feasible to complete valid PM compliance tests during these events. When it is infeasible to reliable conduct valid compliance tests, such as in this case, the CAA section 112(h) allows EPA to establish work practice standards instead of a numerical emissions limit.

When the bypass stack is used, the process concentrate feed will be ceased, but pollution controls will remain operating until no copper is being processed by the converters. During these periods, a charge remains in the electric furnace to ensure the material remains molten, any additional emissions from the smelting process are nominal because the smelting furnace and converters are not operating, and a crust will form on the slag surface of the electric furnace minimizing flow rate and emissions. Only once the crust is formed, the bypass is then opened to vent residual gases prior to conducting maintenance. A CEMS for flow and SO$_2$ or a PM detector at the duct for the bypass stack may be used, and data from the CEMS confirms the emissions during these planned maintenance activities are minimal. We are revising the definition of a bypass stack to reflect this approved purpose.

3. What key comments did we receive on the proposed bypass stack revisions and what are our responses?

Comment: Several commenters supported the EPA's proposal to prohibit the use of bypass stacks, noting that a bypass stack is a negligent mechanism that promotes a reactive rather than a proactive approach to a facility's pollution. One user of bypass stacks disagreed with the proposal to eliminate their use, noting it is overly broad and ignores essential work practices designed to ensure the safe maintenance of process and pollution control equipment. The commenter noted that the bypass is used during maintenance and in particular prior to entering process vessels or confined spaces. In these instances, the commenter explained that the concentrate feed is ceased, but pollution controls remain operating until no more copper is being processed by the converters. During these periods, a charge remains in the electric furnace to ensure the material remains molten, any additional emissions from the smelting process are nominal because the smelting furnace and converters are not operating, and a crust will form on the slag surface of the electric furnace minimizing emissions. The commenter further explained that the bypass is then opened to vent residual gases prior to conducting maintenance. The commenter noted that they operate a CEMS for flow and SO_2 at the duct for the bypass stack, and data from this CEMS confirms the SO_2 emissions during these maintenance activities are minimal. The commenter does not believe it is appropriate for the use of the bypass to be considered a violation of the numerical emission standards of the NESHAP or a bypass of the associated air pollution control devices (APCDs). In the maintenance periods when the bypass is used, emissions are expected to be small and below applicable limits, and air pollution control equipment is either not possible or unnecessary. The commenter recommended that the EPA promulgate work practice standards to regulate the use of the bypass. An additional comment was submitted after the comment period ended which also explained in more detail the challenges of testing the bypass stack siting zero or near zero velocities and volumetric flow rates at the stack.

Response: The EPA has reviewed the information provided and we are establishing a work practice standard for use of the bypass stack to allow planned maintenance of the control devices and processes to be conducted safely. When the bypass stack is used, the work practice must be followed, and the smelting furnaces and converters must not be operating. The control devices will remain operational until a crust is formed on the slag and emissions are minimal. The HAP emission limits are on a concentrate feed basis and during the work practice standards the feed concentrate ceases so the HAP limit is not applicable. Since the bypass stack is only used in planned maintenance, flow rate and SO_2 will be minimal but need to be monitored and emissions are expected to be minimal due to the low or lack of flow rate and when the work practice standards are implemented. We are finalizing the definition ''bypass stack'' in 40 CFR 63.1459. We are also finalizing that the use of a bypass stack during a performance test will invalidate the test. These conditions are consistent with the EPA's interpretation of the application of the court's decision in *Sierra Club* v. *EPA,* 551 F. 3d 1019 (D.C. Cir. 2008).

4. What is the rationale for our final approach and final decisions for bypass stack emissions?

The EPA's rationale for allowing the use of a bypass stack is to ensure safety during essential planned maintenance events, and the approach being finalized ensures that applicable emission limits continue to be met. For this reason, we are promulgating the following work practice standard for the use of bypass stacks at Primary Copper Smelters:

In the case of planned maintenance, feed to the IsaSmelt® Furnace must cease; power to the electric furnace must be lowered and a crust must be allowed to form on the surface of the slag; the operation of the converters must cease and the converters rolled out; and the operation of the anode vessels must cease. Once the main process units are shut down, residual process gases may be re-directed from the acid plant. If the fan to the anode refining point source baghouse is functioning, then the residual process gases must be redirected to the control device. If there is a shutdown or emergency shutdown event, the control devices should continue to run until process emissions cease. If the control devices are shut down before the process emissions cease and the bypass stack is used to vent to the process gas to the atmosphere, there will be a violation of the work practice standards. In addition to this work practice standard, we finalize, as proposed, that the use of a bypass stack is not permitted during compliance performance tests of the processes. We estimate that Freeport will not incur costs to comply with the final work practices because they are already implementing them at their facility.

E. Final Rule Amendments Addressing Compliance Dates

1. What compliance dates did we propose?

In the 2022 proposal, the EPA proposed that existing facilities must comply with the anode refining point source limit within one year. In the supplemental proposal, we proposed a combined roofline PM emission limit with a compliance timeframe of 2 years following promulgation, and a 1-year compliance timeframe following promulgation for emission limits for mercury, HCl, chlorine, D/F, benzene, toluene, PAHs excluding naphthalene, and naphthalene. We also proposed in the supplemental proposal a compliance timeframe of 2 years following promulgation for the co-proposed options for the aisle scrubber at Freeport.

2. How did the compliance dates change since proposal?

We are promulgating option 2 for the aisle scrubber at Freeport, which we expect will require the installation of PM controls (such as a baghouse) to control emissions from the Hoboken converter process fugitive capture system in order to comply with the emission standard (a combined PM limit at the aisle scrubber outlet). Option 2 is being promulgated pursuant to section 112(d)(6); therefore, we are revising its compliance date to 3 years following promulgation. We are also revising the compliance time for anode refining point sources. As discussed in section III.F., for anode refining point sources where the anode emissions are not combined with Hoboken converter process fugitive capture system emissions in an aisle scrubber, we are finalizing the proposed requirement that existing facilities must comply within 1 year after promulgation. For anode refining point sources that combine their anode emissions with Hoboken converter process fugitive capture system emissions in an aisle scrubber, compliance with the anode refining point source limit will be demonstrated through compliance with the combined PM limit at the aisle scrubber outlet and its associated compliance date.

3. What key comments did we receive on the proposed compliance dates and what are our responses?

Comment: Commenters stated that the EPA should allow 3 years for compliance with the combined roofline PM emission limit. The commenters stated there are also significant practical reasons for a 3-year compliance period including the complex design and engineering of the most cost efficient and reliable combination of control options to achieve the targeted emission reductions. According to the commenters, the design and engineering involves multiple time-consuming steps to (i) assess the emission sources, (ii) evaluate the potential control options for effectiveness, reliability and cost, (iii) design engineering of the final scope, (iv) procurement in a current environment where supply issues are common, (v) construction, and finally (vi) startup, which will be challenging to accomplish in 3 years, much less 2.

Response: We acknowledge the complex nature of the engineering involved to evaluate the best controls to use to comply with the final combine roofline PM standard, as well as the potential supply issues; however, the combined roofline PM emission limit is being promulgated pursuant to CAA section 112(f)(2), to address unacceptable risk. Section 112(f)(2) of the CAA allows up to two years after the effective date of a standard to comply if the Administrator finds it is necessary for the installation of controls.

4. What is the rationale for our final approach and final decisions for compliance dates?

We are promulgating compliance times for the standards in the rule based on time frames allowed in CAA, which includes up to 2 years for section 112(f)(2), and up to 3 years for sections 112(d)(2) and (3), and 112(d)(6), along with our judgement of when the standards can be met. The final compliance dates are as follows:

- Three years within promulgation for meeting the combined PM limit for the anode point source emissions that are combined with Hoboken converter process fugitive capture system emissions;
- Three years within promulgation for meeting the anode refining point source standard for anode point source emissions that are combined with Hoboken converter process fugitive capture system emissions;
- One year within promulgation for meeting the anode refining point source standard for anode point source emissions that are not combined with Hoboken converter process fugitive capture system emissions; and
- Two years within promulgation for meeting the combined roofline PM emission limit;
- Three years within promulgation for meeting the combined roofline lead emission limit and design standards;
- One year within promulgation or meeting standards for mercury, HCl, chlorine, D/F, benzene, toluene, PAHs excluding naphthalene, and naphthalene; and
- 180 days within promulgation for all other revisions including compliance with SSM revisions and bypass stack revisions.

For new sources, all standards in the rule are effective immediately upon the effective date of the standard, or upon startup, whichever is later. We are finalizing a new table, table 4, in the 40 CFR part 63, subpart QQQ, to provide the applicability and compliance dates for the new standards to assist facilities with determining these timeframes.

F. Other Major Comments

Comment: A commenter stated that they understood the EPA's assertion that fenceline monitoring is not appropriate for this source category given roof top emissions would not be measured at the fenceline. The Commenter stated that HAP metals tend to deposit within a few miles of the facility and therefore suggested that EPA consider community monitoring similar to those proposed in the Ethylene Oxide Sterilizer Rule.

Another commenter noted that the EPA's assertion that fenceline monitoring is not appropriate for this source category is refuted by EPA's air toxics standards for integrated iron and steel mills (''Steel Mills''), in which the agency finds that fugitive emissions come from heights of 100 feet or more and proposed fenceline monitoring. Alternatively to fenceline monitoring, the EPA could provide for monitors placed higher up, either on existing structures or structures built for the purpose but does not even discuss this possibility.

Response: As stated in the 2023 supplemental proposal, we considered the possibility of a fenceline monitoring requirement and determined that it is not appropriate for this source category. When considering whether fenceline monitoring was appropriate for this source category, we examined the potential for fugitive HAP emissions to be significant, particularly at or near ground level, and whether there are measurement capabilities for the expected pollutants to be monitored, in this case lead and/or arsenic. For this source category, we did not identify any significant sources of ground level emissions. Other considerations included whether there are similar sources located at facilities in other source categories where fenceline monitoring is already being conducted. For example, we recognize that one similarity between integrated iron and steel facilities and primary copper facilities is that both source categories have fugitive metal HAP emissions from roof vents, and as mentioned by the commenter, EPA is requiring fenceline monitoring of chromium at the II&S facilities. However, there are also important differences. First, we are promulgating process fugitive numeric emission limits for the roofline vents at major source primary copper smelters and requirements for annual compliance testing of the roofline vents at these sources. In contrast, the integrated iron and steel final rule (89 FR 23294, April 3, 2024) did not include numeric emission limits for the roofline vents and does not require any emissions testing from the roof vents (other than opacity readings). Instead, in the Integrated Iron and Steel NESHAP, the EPA finalized the following: (1) work practice standards for the basic oxygen process furnaces (BOPFs), Bell Leaks (charging operation) and beaching; and (2) opacity limits for slag processing and planned bleeder valve openings. Secondly, we note that some of the sources of fugitive emissions at integrated iron and steel are at ground level such as slag processing and beaching. We have not identified any significant sources of ground level fugitive emissions at the primary copper smelters. Furthermore, regarding fugitive emissions from the roof vents, unlike Primary Copper facilities (for which we have test data and will obtain future test data through emissions testing requirements), we have no emissions test data from roof vents at integrated iron and steel (II&S) facilities. Therefore, in the integrated iron and steel rulemaking, fenceline monitoring for chromium was proposed and finalized to ensure that the work practices and opacity limits for these unmeasured fugitive and particulate emissions sources at integrated iron and steel facilities are achieving the anticipated reductions.

In addition, we disagree with the commenter's suggestion to place monitors at an elevated height. Fenceline ambient air monitors are typically used to monitor the potential exposure of nearby communities to ground level pollutant emissions; therefore, placing monitors at a height higher than the standard 1.5 meters (the breathing zone) would not be appropriate.

Furthermore, there are lead monitors and arsenic monitors already in the surrounding community nearby the major source facilities, and, as stated in the 2022 proposal, Utah Division of Air Quality (UDAQ), conducted lead ambient monitoring near the area source facility (Kennecott) from January 2010 through June 2017. With EPA's concurrence, this lead monitor was shutdown after UDAQ was able to demonstrate that the likelihood of violating the NAAQS for lead was so low that it was no longer necessary to monitor.

We maintain in the final rule, as stated in the 2023 supplemental proposal, that these characteristics suggest that fenceline monitoring—which is typically used to detect emissions that can be difficult to control or measure at the points where they are emitted, and to identify the need for follow-up investigation and corrective action—would have relatively limited value in the context of this primary copper smelting source category.

We also note that while the EPA's EtO Sterilizers proposal requested comment on the appropriateness of community monitoring, EPA did not propose or finalize fenceline or ambient air monitoring requirements in the EtO Sterilizers rule (88 FR 22790, April 13, 2023; 89 FR 24090, April 5, 2024).

Comment: A commenter stated that process fugitive emissions captured and ducted to a baghouse, emissions from the secondary capture system for the converter department and the anode refining department or the alternative proposed baghouse-based emissions from the converter department should be monitored by PM CEMS to ensure compliance.

Response: The EPA has included PM CEMS as an option for continued compliance in the final rule. Either an operating parameter established during the performance test or PM CEMS will be utilized to demonstrate continued compliance.

V. Summary of Cost, Environmental, and Economic Impacts and Additional Analyses Conducted

A. What are the affected facilities?

The Primary Copper Smelting source category includes any facility that uses a pyrometallurgical process to extract copper from copper sulfur ore concentrates, native ore concentrates, or other copper bearing minerals. There are currently 3 copper smelting facilities: 2 are major sources and 1 is an area source. No new copper smelting facilities are currently being constructed or are planned in the near future.

1. 40 CFR Part 63, Subpart QQQ

The affected sources subject to 40 CFR part 63, subpart QQQ, the major source NESHAP, are copper concentrate dryers, smelting furnaces, slag cleaning vessels, copper converter departments, and fugitive emission sources.

2. 40 CFR Part 63, Subpart EEEEEE

Under 40 CFR part 63, subpart EEEEEE, the area source NESHAP, the affected sources are copper concentrate dryers, smelting vessels, converting vessels, matte drying and grinding plant, secondary gas systems, anode refining furnaces, and anode shaft furnaces.

B. What are the air quality impacts?

The final amendments in this action would achieve about 8.0 tpy (7.99 tpy rounded) reduction of HAP metals emissions (primarily lead, arsenic, cadmium) from process fugitives associated with roofline vents and emissions from the aisle scrubber (combined primary emissions from anode refining department and emissions from the Hoboken converter process fugitive capture system). In this action, we are also finalizing additional work practices that we estimate will achieve some additional unquantified HAP emissions reductions. These final amendments will also reduce risks to public health and the environment, as described above in this preamble.

Furthermore, we are finalizing new standards for mercury, benzene, toluene, HCl, chlorine, PAH, and dioxins/furans. We do not expect to achieve reductions in emissions with these new standards. However, these standards will ensure that the emissions remain controlled and minimized moving forward. The final amendments also include removal of the SSM exemptions.

C. What are the cost impacts?

As described above, the PM standard for the combined emissions from roofline vents would require additional controls to be installed at the Freeport facility. We estimate capital costs of $10.2 million and total annual costs of $2.3 million (includes annual testing costs) for Freeport (2022 dollars). Total annual costs include annualized capital costs, annual operating and maintenance costs, and annual testing costs. Additionally, we estimate that the Freeport facility will need to install additional controls to comply with the emission limit for the combined gas stream including the anode refining point source and the Hoboken converter process fugitive capture system. We estimate capital costs of $59.5 million and total annual costs of $10.8 million will be incurred by Freeport. The Asarco facility will need to install additional controls to comply with the design standards and lead emission limit in this final rule. We estimate capital costs of $15.4 million and total annual costs (including testing) of $3.9 million will be incurred by Asarco.

We expect that both Asarco and Freeport will incur additional costs for compliance testing. The estimated annual costs for performance testing of the previously unregulated HAP are $87,980 for the Freeport facility and $113,340 for the Asarco facility. The estimated annual costs for compliance testing for the anode refining point source and roofline PM emissions standards for the Asarco facility is $138,157.

The total annual costs of all the final requirements (*i.e.,* annualized capital, annual operating and maintenance, and annual emissions testing costs) are estimated to be about $17.3 million. The total capital costs of the final rule are estimated to be about $85.1 million.

D. What are the economic impacts?

The economic impacts associated with this final rule were estimated over an 8-year time frame from 2024 to 2031 using 3 percent and 7 percent discount rates. The present value (PV) of the estimated costs of this final rule, discounted at a 7 percent rate over the 2024 to 2031 period, is $139 million in 2022 dollars. The equivalent annual value (EAV) of the estimated costs is $23 million at a 7 percent discount rate. At a 3 percent discount rate, the PV and EAV of the cost impacts are estimated to be $146 million and $21 million, respectively. This final rule does not impact any small entities.

This final rule is not expected to have significant impacts on domestic copper production; the market price for commercial grade copper or any products comprised of copper inputs; or employment, for several reasons. First, the estimated annual costs of this final rule are expected to be small compared to the potential annual revenues of the U.S. primary copper smelting industry. For example, the U.S. Geological Survey (USGS) estimates 2020 primary copper smelter production was 315,000 mt.[7] Applying an export price for unmanufactured anodes and blister of $5,400 per mt that year, industry revenues in 2020 would have been an estimated $1.7 billion.[8] The estimated annual costs of the final rule ($18 million) represent about one percent of this 2020 annual revenue estimate. Additionally, the affected companies are accustomed to spending large sums on annual maintenance. The 2022 annual report for Freeport-McMoran noted that they spent $87 million on annual maintenance in 2021 at the Miami smelter.[9] The estimated annual costs of this final rule for this Freeport facility are $13 million, which is much lower than those maintenance expenditures. In addition, Freeport benefits from integrating its mining operations with its smelter. By being vertically integrated, Freeport is able to insulate itself from volatility in the cost of

---

[7] See U.S. Geological Survey. Copper Statistics and Information. National Minerals Information Center. Annual Publication for 2020. Available at: *https://www.usgs.gov/centers/national-minerals-information-center/copper-statistics-and-information.* Note that 2020, which was a year of relatively low production compared to previous years is the most recent year for which USGS has this information available.

[8] Ibid.

[9] Freeport -McMoran. 2022 Annual Report. Available at: *https://s22.q4cdn.com/529358580/files/doc_financials/annual/AR_2022.pdf.*

smelting relative to a scenario where it outsources the smelting process. For this reason, the EPA expects that Freeport's incentive to maintain its smelting operation may extend beyond the margins earned solely on the smelting process. The EPA expects that Freeport can comply with this rule while continuing to operate its smelter at a similar capacity as it would under baseline conditions. Finally, due to trade exposure and the commodified nature of copper products (*i.e.,* the interchangeability of copper products manufactured by different producers), the EPA expects that the affected companies are price takers, and thus we would not expect price impacts due to this final rule. The complete economic analysis can be found in the memorandum *Economic Impact Analysis for the Final Residual Risk and Technology Review of the National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelting Sources,* available in the docket.

E. What are the benefits?

1. 40 CFR Part 63, Subpart QQQ

As described above, the final amendments would result in significant reductions in emissions of HAP metals, especially lead and arsenic. Both lead and arsenic are persistent bioaccumulative toxic (PBT) HAPs and developmental toxicants, with particular impacts on infants, children and the developing fetus. The final amendments will reduce risk from the source category to acceptable levels and ensure the NESHAP provides an ample margin of safety to protect public health. The benefits associated with the emission reductions were not able to be monetized but include reductions in both cancer and noncancer (e.g., developmental) endpoints. Some unquantified benefits of these amendments will accrue to Tribal nations living in proximity to these facilities; the reduction in cancer and non-cancer risks due to emissions of PBT HAP metals will benefit Tribal and other communities overburdened by air pollution. The final amendments also revise the standards such that they apply at all times, which includes SSM periods. Furthermore, the final requirements to submit reports and test results electronically will improve monitoring, compliance, and implementation of the rule.

2. 40 CFR Part 63, Subpart EEEEEE

The final amendments under 40 CFR part 63, subpart EEEEEE, revise the standards such that they apply at all times, which includes SSM periods. Furthermore, the final requirements to submit reports and test results electronically will improve monitoring, compliance, and implementation of the rule.

F. What analysis of environmental justice did we conduct?

For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 Technical Guidance for Assessing Environmental Justice in Regulatory Analysis, which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action may involve potential environmental justice (EJ) concerns if it could: (1) create new disproportionate impacts on communities with EJ concerns; (2) exacerbate existing disproportionate impacts on communities with EJ concerns; or (3) present opportunities to address existing disproportionate impacts on communities with EJ concerns through this action under development.

The EPA's EJ technical guidance states that ''[t]he analysis of potential EJ concerns for regulatory actions should address three questions: (A) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline? (B) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration? (C) For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?'' [10]

The environmental justice analysis is presented for the purpose of providing the public with as full as possible an understanding of the potential impacts of this final action. The EPA notes that analysis of such impacts is distinct from the determinations finalized in this action under CAA section 112, which are based solely on the statutory factors the EPA is required to consider under that section.

To examine the potential for Environmental Justice concerns, the EPA conducted a baseline proximity analysis, baseline risk-based analysis (i.e., before implementation of any controls proposed by this action), and post-control risk-based analysis (i.e., after implementation of the controls proposed by this action) for the Freeport facility (tables 4 and 5). The total population, population percentages, and population count for each demographic group for the entire U.S. population are shown in the column titled ''Nationwide Average'' in tables 4 and 5 of this preamble. These national data are provided as a frame of reference.

BILLING CODE 6560–50–P

---

[10] Technical Guidance for Assessing Environmental Justice in Regulatory Analysis, U.S. EPA, June 2016. Quote is from section 3—Key Analytic Considerations, page 11.

Table 4. Comparison of Baseline and Post-Control Demographics of the Population with Cancer Risk Greater than or Equal to 1-in-1 Million and 10-in-1 million Living Within 5 km of the Freeport Primary Copper Smelting Facility

Demographic Group	Nationwide Average	Total Population Living Within 5km	Cancer Risk ≥1-in-1 million		Cancer Risk ≥10-in-1 million	
			Baseline	Post-Control	Baseline	Post-Control
Total Population	330M	6,600	6,600	6,600	1,500	150
Race and Ethnicity by Percent [Number of people]						
White	59 percent [195M]	44 percent [2,900]	44 percent [2,900]	44 percent [2,900]	42 percent [700]	45 percent [<100]
Black	12 percent [40M]	2 percent [200]	2 percent [200]	2 percent [200]	7 percent [100]	8 percent [<100]
American Indian or Alaska Native	0.6 percent [2M]	1.9 percent [100]	1.9 percent [100]	1.9 percent [100]	0.6 percent [<100]	0.0 percent [0]
Hispanic or Latino (includes white and nonwhite)	19 percent [63M]	48 percent [3,200]	48 percent [3,200]	48 percent [3,200]	42 percent [600]	36 percent [<100]
Other and Multiracial	9 percent [30M]	4 percent [200]	4 percent [200]	4 percent [200]	9 percent [100]	11percent [<100]
Income by Percent [Number of People]						
Below Poverty Level	13 percent [43M]	21 percent [1,400]	21 percent [1,400]	21 percent [1,400]	23 percent [400]	27 percent [<100]
Above Poverty Level	87 percent [287M]	79 percent [5,200]	79 percent [5,200]	79 percent [5,200]	77 percent [1,200]	73 percent [100]
Education by Percent [Number of People]						
> 25 w/o a HS Diploma	12 percent [40M]	23 percent [1,500]	23 percent [1,500]	23 percent [1,500]	22 percent [300]	21 percent [<100]
> 25 w/ HS Diploma	88 percent [290M]	77 percent [5,100]	77 percent [5,100]	77 percent [5,100]	78 percent [1,200]	79 percent [100]
Linguistically Isolated by Percent [Number of People]						

Linguistically Isolated	5 percent [17M]	4 percent [300]	4 percent [300]	4 percent [300]	9 percent [100]	11percent [<100]

Notes:

- The nationwide population and all demographic percentages are based on the Census' 2016-2020 American Community Survey 5-year block group averages and include Puerto Rico. The total population count is based on the 2020 Decennial Census block population.
- To avoid double counting, the "Hispanic or Latino" category is treated as a distinct demographic category for these analyses. A person who identifies as Hispanic or Latino is counted as Hispanic/Latino, regardless of what race this person may have also identified as in the Census.

Table 5. Comparison of Baseline and Post-Control Demographics of the Population with Cancer Risk Greater than or Equal to 1-in-1 Million and 10-in-1 million Living Within 50 km of the Freeport Primary Copper Smelting Facility

Demographic Group	Nationwide Average	Total Population Living Within 50km	Cancer Risk ≥1-in-1 million		Cancer Risk ≥10-in-1 million	
			Baseline	Post-Control	Baseline	Post-Control
Total Population	330M	32,300	21,900	16,000	4,600	150
Race and Ethnicity by Percent [number of people]						
White	59 percent [195M]	38 percent [12,400]	36 percent [7,900]	49 percent [7,800]	45 percent [2,100]	45 percent [<100]
Black	12 percent [40M]	0.7 percent [200]	1 percent [200]	1 percent [200]	3 percent [100]	8 percent [<100]
American Indian or Alaska Native	0.6 percent [2M]	24 percent [7,800]	24 percent [5,700]	4 percent [640]	1 percent [<100]	0 percent [0]
Hispanic or Latino (includes white and nonwhite)	19 percent [63M]	33 percent [10,700]	33 percent [7,200]	42 percent [6,700]	44 percent [2,000]	36 percent [<100]
Other and Multiracial	9 percent [30M]	4 percent [1,300]	4 percent [900]	4 percent [600]	7 percent [300]	11 percent [<100]
Income by Percent [Number of People]						
Below Poverty Level	13 percent [43M]	23 percent [7,400]	24 percent [5,300]	16 percent [2,600]	14 percent [600]	27 percent [<100]
Above Poverty Level	87 percent [287M]	77 percent [24,900]	76 percent [16,600]	84 percent [13,400]	86percent [4,000]	73 percent [100]

Education by Percent [Number of People]						
> 25 w/o a HS Diploma	12 percent [40M]	17 percent [5,500]	18 percent [3,900]	16 percent [2,600]	14 percent [600]	21 percent [<100]
> 25 w/ HS Diploma	88 percent [290M]	83 percent [26,800]	82 percent [18,000]	84 percent [13,400]	86 percent [4,000]	79 percent [100]
Linguistically Isolated by Percent [Number of People]						
Linguistically Isolated	5 percent [17M]	3 percent [1,000]	3 percent [700]	2 percent [300]	4 percent [200]	11 percent [<100]

Notes:

- The nationwide population and all demographic percentages are based on the Census' 2016-2020 American Community Survey 5-year block group averages and include Puerto Rico. The total population count is based on the 2020 Decennial Census block population.
- To avoid double counting, the "Hispanic or Latino" category is treated as a distinct demographic category for these analyses. A person who identifies as Hispanic or Latino is counted as Hispanic/Latino, regardless of what race this person may have also identified as in the Census.

BILLING CODE 6560–50–C

The baseline proximity demographic analysis is an assessment of individual demographic groups in the total population living within 5 km (~3.1 miles) and 50 km (~31 miles) of the facility. Approximately 32,300 and 6,600 people live within 50km and 5 km, respectively of the Freeport facility. The results of the proximity demographic analysis indicate that the percent of the population that is Hispanic or Latino and that is American Indian or Alaska Native is higher than the corresponding national averages. This is particularly true for the population within 50km, which is 24 percent American Indian or Alaska Native, which is significantly above the 0.6 percent national average. The percent of people living below the poverty level and percent of people over the age of 25 without a high school diploma are also higher than the national averages.

The risk-based demographic analysis focused on the populations living within 5 km (~3.1 miles) and 50 km of the Freeport facility with estimated cancer risks greater than or equal to 1-in-1 million and greater than or equal to 10-in-1 million resulting from Primary Copper Smelting source category emissions. The baseline risk analysis indicated that emissions from the source category, prior to controls in this action, expose 6,600 people living within 5 km and 21,900 people living within 50 km to a cancer risk greater than or equal to 1-in-1 million, and 1,500 people living within 5 km and 4,600 people living within 50 km to a cancer risk greater than or equal to 10-in-1 million. The post-control risk-based demographic analysis, which is an assessment of risks to individual demographic groups in the population living within 5 km and 50 km of the facilities after implementation of the controls in this action (''post-control''), indicated that post-control emissions from the source category expose 6,600 people living within 5 km and 16,000 people living within 50 km to a cancer risk greater than or equal to 1-in-1 million and 150 people living within 5 km and 150 people living within 50 km to a cancer risk greater than or equal to 10-in-1 million.

The demographics of the population living within 5 km with baseline cancer risks greater than or equal to 1-in-1 million is the same as the total population living within 5 km (i.e., all individuals living within 5 km have a baseline cancer risk greater than or equal to 1-in-1 million). Also, since the controls do not reduce the number of individuals living within 5km with risks greater than or equal to 1-in-1 million, the post-control demographics are also the same as the baseline. The demographics of the population living within 5 km with baseline and post-control cancer risks greater than or equal to 10-in-1 million indicates that the percentage of the population that is Hispanic or Latino, living below the poverty level, over 25 without a high school diploma and in linguistic isolation are significantly above the corresponding national averages. However, the number of individuals exposed to post-control risks greater than or equal to 10-in-1 million is reduced by a factor of 10 for each demographic.

The demographics of the population living within 50 km with baseline cancer risks greater than or equal to 1-in-1 million indicates that the percentage of the population that is American Indian or Alaska Native, Hispanic or Latino, living below the poverty level, over 25 without a high school diploma and in linguistic isolation are significantly above the corresponding national averages. The demographics of the population living within 50 km with post-control cancer risks greater than or equal to 1-in-1 million indicates that the percentage of the population that is Hispanic or Latino, living below the poverty level, over 25 without a high school diploma and in linguistic isolation are significantly above the corresponding national averages. The percentage of the population that is American Indian or Alaska Native with post-control cancer risks greater than or equal to 1-in-1 million dropped significantly from 24 percent to 4 percent, with the number of American Indian or Alaska Native individuals at this risk level dropping from 5,700 in the baseline to 640 post-control.

The demographics of the population living within 50 km with baseline cancer risks greater than or equal to 10-in-1 million indicates that the percentage of the population that is Hispanic or Latino is significantly above the national average. The percentage of the population that is living below the poverty level or over 25 without a high school diploma are closer to the national averages. The number of individuals living within 50 km exposed to post-control risks greater than or equal to 10-in-1 million is reduced by about a factor of 30 for each demographic.

The EPA provided meaningful participation opportunities for communities with environmental justice concerns. The EPA proposed the Primary Copper Smelting NESHAP in January 2022, and received comments, and published a supplemental proposal in July of 2023, and received additional comments. Communities with environmental justice concerns had the opportunity to comment and request public hearings in response to both proposals. The EPA received a combined comment from the San Carlos Apache Tribe, Sierra Club, and Earthjustice; comment from The National Tribal Air Association; a combined comment from several non-governmental organizations including but not limited to the Allergy and Asthma Network and the Children's Environmental Health Network. Section IV. of this preamble provides a summary of key comments and responses. For all comments not discussed in this preamble, comment summaries and the EPA's responses can be found in the *National Emission Standards for Hazardous Air Pollutant Emissions: Primary Copper Smelting Residual Risk and Technology Review and Primary Copper Smelting Area Source Technology Review: Summary of Public Comments and Responses* document, available in the docket for this action (Docket ID No. EPA–HQ–OAR–2020–0430). In addition to the response to comments, the EPA conducted outreach with potentially affected communities by participating in the National Tribal Air Association calls and conducted Tribal consultations during this rule making process. We believe this final action will reduce adverse human health or environmental effects on communities with environmental justice concerns and that the EPA provided meaningful participation opportunities for these communities to participate in the development of this action.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Orders 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a ''significant regulatory action'' as defined in Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket. The EPA prepared an economic analysis of the potential impacts associated with this action. This analysis, *Economic Impact Analysis for the Final Residual Risk and Technology Review of the National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelting Sources*, is also available in the docket.

B. Paperwork Reduction Act (PRA)

1. 40 CFR Part 63, Subpart QQQ

The information collection activities in this final rule have been submitted for approval to OMB under the PRA. The ICR document that the EPA prepared has been assigned OMB Control Number 2060–0476 and EPA ICR number 1850.10. You can find a copy of the ICR in the docket for this action, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

In this action, we are finalizing amendments that require electronic reporting of results of performance tests and CEMS performance evaluations, fugitive dust plans and notification of compliance reports, remove the requirement to submit certain information related to the malfunction exemption, and impose other rule revisions that affect reporting and recordkeeping requirements for primary copper smelting facilities, such as requirements to submit new performance test reports and to maintain new operating parameter records to demonstrate compliance with new standards. This information will be collected to assure compliance with 40 CFR part 63, subpart QQQ.

Respondents/affected entities: Owners or operators of primary copper smelting facilities. Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart QQQ).

Estimated number of respondents: Two (total). Frequency of response: Initial, semiannual, and annual.

Total estimated burden: The annual recordkeeping and reporting burden for facilities to comply with all of the requirements in the NESHAP is estimated to be 6,500 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: The annual recordkeeping and reporting burden for facilities to comply with all of the requirements in the NESHAP is estimated to be $860,000 (per year), of which $150,000 is for this rule, and $710,000 is for the other costs related to continued compliance with the NESHAP.

There are no annualized capital costs. There are an estimated $302,000 in operation & maintenance costs associated with periodic performance testing.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR Part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

2. 40 CFR Part 63, Subpart EEEEEE

The information collection activities in this final rule have been submitted for approval to OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2240.09. You can find a copy of the ICR in the docket for this action, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

In this action, we are finalizing amendments that require electronic reporting of results of performance tests and CEMS performance evaluations and notification of compliance reports, remove the malfunction exemption, and impose other revisions that affect reporting and recordkeeping for primary copper smelting facilities. This information will be collected to assure compliance with 40 CFR part 63, subpart EEEEEE.

Respondents/affected entities: Owners or operators of primary copper smelting facilities. Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart EEEEEE).

Estimated number of respondents: One (total).

Frequency of response: Initial, semiannual, and quarterly.

Total estimated burden: The annual recordkeeping and reporting burden for facilities to comply with all of the requirements in the NESHAP is estimated to be 15 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: The annual recordkeeping and reporting burden for facilities to comply with all of the requirements in the NESHAP is estimated to be $1,973 (per year).

There are no annualized capital or operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. Based on the Small Business Administration size category for this source category, no small entities are subject to this action.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any State, local, or Tribal governments or the private sector.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the National Government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have Tribal implications as specified in Executive Order 13175. The Executive order defines Tribal implications as ''actions that have substantial direct effects on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes''. Based on all of our analyses, we conclude that the amendments in this action will not have a substantial direct effect on one or more Tribes, change the relationship between the Federal Government and Tribes, or affect the distribution of power and responsibilities between the Federal Government and Indian Tribes. Thus, Executive Order 13175 does not apply to this action.

Although this action does not have Tribal implications as defined by Executive Order 13175, consistent with the EPA policy on coordination and consultation with Indian Tribes, the EPA offered government-to-government consultation with Tribes during the rulemaking process. The EPA held a consultation with the San Carlos Apache Tribe on June 7, 2022, to discuss the 2022 proposal (Docket ID No. EPA–HQ–OAR–2020–0430–0185) and ensure that the views of the San Carlos Apache Tribe were taken into consideration in the rulemaking process in accordance with the *EPA Policy on Consultation with Indian Tribes (December 2023). The EPA Policy on Consultation with Indian Tribes* is available in the docket for this action. The topics discussed during the consultation are described in the consultation request letter, dated April 4, 2022 (Docket ID No. EPA–HQ–OAR–2020–0430–0139). In addition, the EPA also received letters from representatives of the San Carlos Apache Tribe expressing their concerns due to emissions of lead and arsenic from the primary copper smelting facilities, which are available in the docket for this action. In the letter, dated September 21, 2023 (which is available in the docket for this action), the Tribe requested consultation. We reached out to the Tribe on several occasions to schedule consultation but did not receive a response.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is not subject to Executive Order 13045 because it is not a significant regulatory action under section 3(f)(1) of Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action's health and risk assessments are contained in sections III. and IV. of this preamble and further documented in the document titled *Freeport Baseline and Control Options Re-model Risk Analysis Memo,* which is available in the docket for this rule (Docket ID No. EPA–HQ–OAR–2020–0430).

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. We have concluded that this action is not likely to have any adverse energy effects because it contains no regulatory requirements that will have an adverse impact on productivity, competition, or prices in the energy sector.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This rulemaking involves technical standards. Therefore, the EPA conducted searches for the 2022 proposal and 2023 supplemental proposal through the Enhanced NSSN Database managed by the American National Standards Institute (ANSI). The Agency also contacted VCS organizations and accessed and searched their databases. Searches were conducted for the EPA Methods 1, 1A, 2, 2A, 2C, 2D, 2F, 2G, 3, 3A, 3B, 4, 5, 5B, 5D, 9, 17, 18, 22, 23, 26A, 29, 30A, and 30B of 40 CFR part 60, appendix A, and EPA Method 201A of 40 CFR part 51, appendix M. No applicable VCS were identified for EPA Method 1A, 2A, 2D, 2F, 2G, 5B, 5D, 22, 30A, 30B, or 201A. During the searches, if the title or abstract (if provided) of the VCS described technical sampling and analytical procedures that are similar to the EPA's reference method, the EPA considered it as a potential equivalent method. All potential standards were reviewed to determine the practicality of the VCS for this rule. This review requires significant method validation data which meets the requirements of the EPA Method 301 for accepting alternative methods or scientific, engineering and policy equivalence to procedures in the EPA reference methods. The EPA may reconsider determinations of impracticality when additional information is available for particular VCS. Four VCS were identified as an acceptable alternative to the EPA test methods for the purposes of this rule.

The VCS ANSI/ASME PTC 19.10–1981 Part 10, Flue and Exhaust Gas Analyses, is an acceptable alternative to the EPA Method 3B manual portion only and not the instrumental portion. The ANSI/ASME PTC 19.10–1981 Part 10 method incorporates both manual and instrumental methodologies for the determination of O^2 content. The manual method segment of the O^2 determination is performed through the absorption of O2. This VCS may be obtained from *https://webstore.ansi.org/* or from the ANSI Headquarters at 1899 L Street NW, 11th Floor, Washington, DC 20036.

The VCS ASTM D7520–16, *Standard Test Method for Determining the Opacity of a Plume in the Outdoor*

Ambient Atmosphere, is an instrumental method to determine plume opacity in the outdoor ambient environment as an alternative to visual measurements made by certified smoke readers in accordance with EPA Method 9. The concept of ASTM D7520–16, also known as the Digital Camera Opacity Technique or DCOT, is a test protocol to determine the opacity of visible emissions using a digital camera. It was based on previous method development using digital still cameras and field testing of those methods. The purpose of ASTM D7520–16 is to set a minimum level of performance for products that use DCOT to determine plume opacity in ambient environments. The ASTM D7520–16 is an acceptable alternative to the EPA Method 9 with the following conditions:

1. During the digital camera opacity technique (DCOT) certification procedure outlined in section 9.2 of ASTM D7520–16, you or the DCOT vendor must present the plumes in front of various backgrounds of color and contrast representing conditions anticipated during field use such as blue sky, trees, and mixed backgrounds (clouds and/or a sparse tree stand).
2. You must also have standard operating procedures in place including daily or other frequency quality checks to ensure the equipment is within manufacturing specifications as outlined in section 8.1 of ASTM D7520–16.
3. You must follow the record keeping procedures outlined in 40 CFR 63.10(b)(1) for the DCOT certification, compliance report, data sheets, and all raw unaltered Joint Photographic Experts Group (JPEG) files used for opacity and certification determination.
4. You or the DCOT vendor must have a minimum of four (4) independent technology users apply the software to determine the visible opacity of the 300 certification plumes. For each set of 25 plumes, the user may not exceed 15 percent opacity of anyone reading and the average error must not exceed 7.5 percent opacity.
5. This approval does not provide or imply a certification or validation of any vendor's hardware or software. The onus to maintain and verify the certification and/or training of the DCOT camera, software and operator in accordance with ASTM D7520–16 and this letter is on the facility, DCOT operator, and DCOT vendor.

The voluntary consensus standard ASTM D6420–99 (Reapproved 2010), *Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry,* employs a direct interface gas chromatograph/mass spectrometer (GCMS) to identify and quantify the 36 volatile organic compounds (or sub-set of these compounds). This ASTM procedure has been approved by the EPA as an alternative to EPA Method 18 only when the target compounds are all known and the target compounds are all listed in ASTM D6420 as measurable.

The VCS ASTM D6784–16, *Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method),* is an acceptable alternative to the EPA Methods 101A and 29 (portion for mercury only) as a method for measuring mercury. This method applies to concentrations approximately 0.5–100 µg/Nm3. This test method describes equipment and procedures for obtaining samples from effluent ducts and stacks, equipment and procedures for laboratory analysis, and procedures for calculating results.

The ASTM standards are available from ASTM at *https://www.astm.org* or 1100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, telephone number: (610) 832–9500, fax number: (610) 832–9555 email address: *service@astm.org.*

The searches conducted for the 2022 proposal and 2023 supplemental proposal identified 26 VCS that were potentially applicable for these rules in lieu of the EPA reference methods. After reviewing the available standards, the EPA determined that 26 candidate VCS (ASTM D3154–00 (2014), ASTM D3464–96 (2014), ASTM 3796–09 (2016), ASTM D3796–90 (2004) ISO 10780:1994 (2016), ASME B133.9–1994 (2001), ISO 10396:(2007), ANSI/ASME PTC 19–10–1981—Part 10 (2010) Flue and Exhaust Gas Analyses—Instrumental Procedure Only, ISO 12039:2001 (2012), ASTM D5835–95 (2013), ASTM D6522–11, CAN/CSA Z223.2–M86 (R1999), ISO 9096:1992 (2003), ANSI/ASME PTC–38–1980 (1985), ASTM D3685/D3685M– 98–13, CAN/CSA Z223.1–M1977, National Institute of Occupational Safety and Health (NIOSH) Method 2010 ''Amines, Aliphatic'', ASTM D6060–96 (2009), EN 1948–3 (2006), EN 1911–1,2,3 (1998), ASTM D6735–01 (2009), ISO 10397:1993, ASTM D6331 (2014), EN13211:2001, CAN/CSA Z223.26–M1987, ASTM E1979–21, ASTM D4358–05) identified for measuring emissions of pollutants or their surrogates subject to emission standards in the rule would not be practical due to lack of equivalency, documentation, validation data and other important technical and policy considerations. Additional information for the VCS search and determinations can be found in the memorandums *Voluntary Consensus Standard Results for National Emission Standards for Hazardous Air Pollutants: Primary Copper Smelting Residual Risk and Technology Review and Primary Copper Smelting Area Source Technology Review* (Docket ID No. EPA–HQ–OAR–2020–0430–0065) and *Voluntary Consensus Standard Results for National Emission Standards for Hazardous Air Pollutants: Primary Copper Smelting Residual Risk and Technology Review and Primary Copper Smelting Area Source Technology Review and Voluntary Consensus Standard Results for National Emission Standards of Hazardous Air Pollutants: Primary Copper Smelting Supplemental Proposal* (Docket ID No. EPA–HQ–OAR–2020–0430–0150), which are available in the docket for this action. Under 40 CFR 63.7(f) and 63.8(f), a source may apply to the EPA to use alternative test methods or alternative monitoring requirements in place of any required testing methods, performance specifications or procedures in the final rule or any amendments.

The EPA is also incorporating by reference EPA/100/R–10/005, *Recommended Toxicity Equivalence Factors (TEFs) for Human Health Risk Assessments of 2, 3, 7, 8-Tetrachlorodibenzo-p-dioxin and Dioxin-Like Compounds,* December 2010. This is the international method of expressing toxicity equivalents for dioxins/furans where a recommended toxicity equivalent factor (TEF) is multiplied by each individual compound's (congener) emission concentration to calculate the toxic equivalent quotient (TEQ). To estimate risk associated with the mixture, the dose-response function for the index chemical is evaluated at this sum, which is an estimate of the total index chemical equivalent dose for the mixture components being considered. This method may be obtained from *https://www.epa.gov/sites/default/files/2013-09/documents/tefs-for-dioxin-epa-00-r-10-005-final.pdf.* or U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue NW, Washington, DC 20460, (202) 272–0167, *https://www.epa.gov.*

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

The EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with environmental justice concerns. The EPA evaluated the demographic characteristics of communities located near the major source facilities and determined that elevated cancer risks associated with emissions from these facilities disproportionately affect Native American, Hispanic, populations Below Poverty Level and Over 25 without High School Diploma individuals living nearby. As part of its environmental justice analysis, EPA evaluated whether the final action for the Primary Copper Smelting Major Source Category would address the existing disproportionately high and adverse human health effect on these individuals and EPA further evaluated the projected distribution of reductions in risk resulting from this action.

The EPA believes that this action is likely to reduce existing disproportionate and adverse effects on communities with environmental justice concerns. The agency estimated the MIR at Freeport will be reduced from 70-in-1 million to 20-in-1 million and the population with cancer risks greater than or equal to 1-in-1 million will be reduced from 21,875 to 16,962 because of this action. We estimate that the maximum chronic noncancer inhalation TOSHI will be reduced from 1 to less than 1 (0.3), and the acute HQ will be reduced from a value of 7 to 2 at Freeport. Given the uncertainties in the emissions data at Asarco and the short timeframe to complete the final rule, we did not evaluate the impact of the final standards on the population living in the vicinity of the Asarco facility. The standards in this final rule are estimated to reduce metal HAP emissions, primarily lead and arsenic, from this source category by 8.0 tpy.

The methodology and the results of the demographic analysis are presented in section V.F. of this preamble and in the technical report *Risk and Technology Review—Analysis of Demographic Factors for Populations Living Near Primary Copper Smelting Source Category Operations—Final Rule* (Docket ID No. EPA–HQ–OAR–2020–0430). The information supporting this Executive order review is contained in section V.F. of this preamble.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedures, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Michael S. Regan,
Administrator.

For the reasons stated in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 et seq.

Subpart A—General Provisions

■ 2. Amend § 63.14 by revising paragraphs (f)(1) and (i)(95), (105), and (110) and adding paragraph (o)(30) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(f) * * *

(1) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], issued August 31, 1981, IBR approved for §§ 63.309(k); 63.365(b); 63.457(k); 63.772(e) and (h); 63.865(b); 63.997(e); 63.1282(d) and (g); 63.1450(a), (b), (d), and (e) through (g); 63.1625(b); table 5 to subpart EEEE; §§ 63.3166(a); 63.3360(e); 63.3545(a); 63.3555(a); 63.4166(a); 63.4362(a); 63.4766(a); 63.4965(a);63.5160(d); table 4 to subpart UUUU; table 3 to subpart YYYY; §§ 63.7822(b); 63.7824(e); 63.7825(b); 63.8000(d); 63.9307(c); 63.9323(a); 63.9621(b) and (c); 63.11148(e); 63.11155(e); 63.11162(f); 63.11163(g); 63.11410(j); 63.11551(a); 63.11646(a); 63.11945; table 4 to subpart AAAAA; table 5 to subpart DDDDD; table 4 to subpart JJJJJ; table 4 to subpart KKKKK; table 4 to subpart SSSSS; tables 4 and 5 to subpart UUUUU; table 1 to subpart ZZZZZ; table 4 to subpart JJJJJJ.

* * * * *

(i) * * *

(95) ASTM D6420–99 (Reapproved 2010), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, Approved October 1, 2010, IBR approved for §§ 63.670(j); table 4 to subpart UUUU; 63.1450(f); 63.7142(b); appendix A to this part.

* * * * *

(105) ASTM D6784–16, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), Approved March 1, 2016; IBR approved for §§ 63.1450(d); 63.9621; table 5 to subpart UUUUU; appendix A to subpart UUUUU.

* * * * *

(110) ASTM D7520–16, Standard Test Method for Determining the Opacity of a Plume in the Outdoor Ambient Atmosphere, approved April 1, 2016; IBR approved for §§ 63.1450(c), (e), and (g); 63.1453(h); 63.1625(b); table 3 to subpart LLLLL; §§ 63.7823(c) through (e); 63.7833(g); 63.11423(c).

* * * * *

(o) * * *

(30) EPA/100/R–10/005, Recommended Toxicity Equivalence Factors (TEFs) for Human Health Risk Assessments of 2, 3, 7, 8-Tetrachlorodibenzo-p-dioxin and Dioxin-Like Compounds, December 2010; IBR approved for § 63.1459 and table 2 to subpart QQQ. (Available at https://www.epa.gov/sites/default/files/2013-09/documents/tefs-for-dioxin-epa-00-r-10-005-final.pdf.)

* * * * *

■ 3. Effective July 15, 2024, further amend § 63.14 by:

■ a. Revising paragraphs (f)(1) and (i)(110);

■ b. Redesignating paragraphs (o)(1) through (30) as paragraphs (o)(2) through (31); and

■ c. Adding new paragraph (o)(1).

The revisions and addition read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(f) * * *

(1) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], issued August 31, 1981, IBR approved for §§ 63.116(c); 63.116 and (h); 63.128(a); 63.145(i); 63.309(k); 63.365(b); 63.457(k); 63.490(g); 63.772(e) and (h); 63.865(b); 63.997(e); 63.1282(d) and (g); 63.1450(a), (b), and (e) through (g); 63.1625(b); table 5 to subpart EEEE; §§ 63.3166(a); 63.3360(e); 63.3545(a); 63.3555(a); 63.4166(a); 63.4362(a); 63.4766(a); 63.4965(a); 63.5160(d); table 4 to subpart UUUU; table 3 to subpart YYYY; §§ 63.7822(b); 63.7824(e); 63.7825(b); 63.8000(d); 63.9307(c); 63.9323(a); 63.9621(b) and (c); 63.11148(e); 63.11155(e); 63.11162(f);

63.11163(g); 63.11410(j); 63.11551(a); 63.11646(a); 63.11945; table 4 to subpart AAAAA; table 5 to subpart DDDDD; table 4 to subpart JJJJJ; table 4 to subpart KKKKK; table 4 to subpart SSSSS; tables 4 and 5 to subpart UUUUU; table 1 to subpart ZZZZZ; table 4 to subpart JJJJJJ.

* * * * *

(i) * * *

(110) ASTM D7520–16, Standard Test Method for Determining the Opacity of a Plume in the Outdoor Ambient Atmosphere, approved April 1, 2016; IBR approved for §§ 63.1450(c), (e), and (g); 63.1453(h); 63.1625(b); table 3 to subpart LLLLL; §§ 63.7823(c) through (f), 63.7833(g); 63.11423(c).

* * * * *

(o) * * *

(1) EPA/100/R–10/005, Recommended Toxicity Equivalence Factors (TEFs) for Human Health Risk Assessments of 2, 3, 7, 8-Tetrachlorodibenzo-p-dioxin and Dioxin-Like Compounds, December 2010; IBR approved for § 63.1459 and table 2 to subpart QQQ. (Available at https://www.epa.gov/sites/default/files/2013-09/documents/tefs-for-dioxin-epa-00-r-10-005-final.pdf).

* * * * *

■ 4. Revise subpart QQQ, consisting of §§ 63.1440 through 63.1459, to read as follows:

Subpart QQQ—National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelting

Sec.

Subpart QQQ—National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelting

§ 63.1440 What is the purpose of this subpart?

This subpart establishes national emission standards for hazardous air pollutants (NESHAP) for primary copper smelters. This subpart also establishes requirements to demonstrate initial and continuous compliance with all applicable emission limitations, work practice standards, design standards, and operation and maintenance requirements in this subpart.

§ 63.1441 Am I subject to this subpart?

You are subject to this subpart if you own or operate a primary copper smelter that is (or is part of) a major source of hazardous air pollutant (HAP) emissions on the first compliance date that applies to you (see § 63.1443). Your primary copper smelter is a major source of HAP if it emits or has the potential to emit any single HAP at the rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year.

§ 63.1442 What parts of my plant does this subpart cover?

(a) This subpart applies to each new and existing affected source at your primary copper smelter. The affected sources are each copper concentrate dryer, each smelting vessel, each slag cleaning vessel, each copper converter department, each anode refining department, process fugitive emission sources (i.e., roofline vents) from smelting vessels, slag cleaning vessels, copper converter department and anode refining department, each bypass stack, and the entire group of fugitive dust sources, as defined in § 63.1459.

(b) The following affected sources: each copper concentrate dryer, each smelting vessel, each slag cleaning vessel, each copper converter department, and the entire group of fugitive dust sources at your primary copper smelter are existing if you commenced construction or reconstruction of the affected source before April 20, 1998.

(c) The following affected sources: each copper concentrate dryer, each smelting vessel, each slag cleaning vessel, each copper converter department and the entire group of fugitive dust sources at your primary copper smelter are new if you commenced construction or reconstruction of the affected source on or after April 20, 1998. An affected source is reconstructed if it meets the definition of ''reconstruction'' in § 63.2.

(d) The following affected sources: each anode refining department and process fugitive emission sources (*i.e.,* roofline vents) from smelting vessels, slag cleaning vessels, copper converter department and anode refining department are existing if you commenced construction or reconstruction of the affected source before January 11, 2022.

(e) The following affected sources: each anode refining department and process fugitive emission sources (i.e., roofline vents) from smelting vessels, slag cleaning vessels, copper converter department and anode refining department at your primary copper smelter are new if you commenced construction or reconstruction of the affected source on or after January 11, 2022. An affected source is reconstructed if it meets the definition of ''reconstruction'' in § 63.2.

(f) The bypass stack is existing if you commenced construction or reconstruction of the affected source before July 24, 2023.

(g) The bypass stack is new if you commenced construction or reconstruction of the affected source on or after July 24, 2023. An affected source is reconstructed if it meets the definition of ''reconstruction'' in § 63.2.

§ 63.1443 When do I have to comply with this subpart?

(a) If you have an existing affected source, you must comply with each emission limitation, work practice standard, design standard, and operation and maintenance requirement in this subpart that applies to you no later than June 13, 2005, except as specified in table 4 to this subpart.

(b) If you have a new affected source and its initial startup date is on or before June 12, 2002, you must comply with each emission limitation, work practice standard, design standard, and operation and maintenance requirement in this subpart that applies to you by June 12, 2002, except as specified in table 4 to this subpart.

(c) If you have a new affected source and its initial startup date is after June 12, 2002, you must comply with each emission limitation, work practice standard, design standard, and operation and maintenance requirement in this subpart that applies to you upon initial startup, except as specified in in table 4 to this subpart.

(d) If your primary copper smelter is an area source that becomes a major source of HAP (see § 63.1441), the compliance dates listed in paragraphs (d)(1) and (2) of this section apply to you.

(1) Any portion of the existing primary copper smelter that is a new affected source or a new reconstructed source must be in compliance with this subpart upon startup.

(2) All other parts of the primary copper smelter must be in compliance with this subpart no later than 3 years after it becomes a major source (see § 63.1441).

(e) You must meet the notification and schedule requirements in § 63.1454. Several of these notifications must be submitted before the compliance date for your affected source.

§ 63.1444 What emissions limitations, work practice standards, and design standards must I meet for my copper concentrate dryers, smelting vessels, slag cleaning vessels, copper converter departments, anode refining departments, process fugitive emissions from roofline vents, and bypass stacks?

(a) *Copper concentrate dryers.* For each copper concentrate dryer, you must comply with the emission limitation in paragraph (a)(1) or (2) of this section that applies to you.

(1) For each existing copper concentrate dryer, you must not cause to be discharged to the atmosphere from the dryer vent any gases that contain filterable particulate matter in excess of 50 milligrams per dry standard cubic meter (mg/dscm) as measured using the test methods specified in § 63.1450(a).

(2) For each new copper concentrate dryer, you must not cause to be discharged to the atmosphere from the dryer vent any gases that contain filterable particulate matter in excess of 23 mg/dscm as measured using the test methods specified in § 63.1450(a).

(b) *Smelting vessels.* For each smelting vessel, you must comply with the emission limitations and work practice standards in paragraphs (b)(1) and (2) of this section.

(1) For each smelting vessel, you must not cause to be discharged to the atmosphere any process off-gas that contains nonsulfuric acid particulate matter in excess of 6.2 mg/dscm as measured using the test methods specified in § 63.1450(b). Process off-gas from a smelting vessel is generated when copper ore concentrates and fluxes are being smelted to form molten copper matte and slag layers.

(2) For each smelting vessel, you must control the process fugitive emissions released when tapping copper matte or slag from the smelting vessel according to paragraphs (b)(2)(i) and (ii) of this section.

(i) At all times when copper matte or slag is tapped from the smelting vessel, you must operate a capture system that collects the gases and fumes released from the tapping port in use. The design and placement of this capture system must be such that the tapping port opening, launder, and receiving vessel (e.g., ladle, slag pot) are positioned within the confines or influence of the capture system's ventilation draft during those times when the copper matte or slag is flowing from the tapping port opening.

(ii) You must not cause to be discharged to the atmosphere from the capture system used to comply with paragraph (b)(2)(i) of this section any gases that contain filterable particulate matter in excess of 23 mg/dscm as measured using the test methods specified in § 63.1450(a).

(c) *Slag cleaning vessels.* For each slag cleaning vessel, you must comply with the emission limitations and work practice standards in paragraphs (c)(1) through (3) of this section that apply to you.

(1) For each slag cleaning vessel, except as provided for in paragraph (c)(2) of this section, you must not cause to be discharged to the atmosphere any process off-gas that contains nonsulfuric acid particulate matter in excess of 6.2 mg/dscm as measured using the test methods specified in § 63.1450(b).

(2) As an alternative to complying with the emission limit for nonsulfuric acid particulate matter in paragraph (c)(1) of this section, for each existing slag cleaning vessel you may choose to comply with the emission limit for filterable particulate matter specified in this paragraph (c)(2). You must not cause to be discharged to the atmosphere any process off-gas that contains filterable particulate matter in excess of 46 mg/dscm as measured using the test methods specified in § 63.1450(a).

(3) For each slag cleaning vessel, you must control process fugitive emissions released when tapping copper matte or slag from the slag cleaning vessel according to paragraphs (c)(3)(i) and (ii) of this section.

(i) At all times when copper matte or slag is tapped from the slag cleaning vessel, you must operate a capture system that collects the gases and fumes released from the tapping port in use. The design and placement of this capture system must be such that the tapping port opening, launder, and receiving vessel (e.g., ladle, slag pot) are positioned within the confines or influence of the capture system's ventilation draft during those times when the copper matte or slag is flowing from the tapping port opening.

(ii) You must not cause to be discharged to the atmosphere from the capture system used to comply with paragraph (c)(3)(i) of this section any gases that contain filterable particulate matter in excess of 23 mg/dscm as measured using the test methods specified in § 63.1450(a).

(d) *Existing copper converter departments.* For each existing copper converter department, you must comply with the emission limitations and work practice standards in paragraphs (d)(1) through (6) of this section that apply to you.

(1) You must operate a capture system that collects the process off gas vented from each batch copper converter. At all times when one or more batch copper converters are blowing, you must operate the capture system according to the written operation and maintenance plan that has been prepared according to the requirements in § 63.1447(b).

(2) If your copper converter department uses Peirce-Smith converters, the capture system design must include use of a primary hood that covers the entire mouth of the converter vessel when the copper converter is positioned for blowing. Additional hoods (e.g., secondary hoods) or other capture devices must be included in the capture system design as needed to achieve the opacity limit in paragraph (d)(4) of this section. The capture system design may use multiple intake

and duct segments through which the ventilation rates are controlled independently of each other, and individual duct segments may be connected to separate control devices.

(3) If your copper converter department uses Hoboken converters, the capture system must collect all process off-gas vented during blowing through the side-flue intake on each converter vessel.

(4) You must operate the capture system such that any visible emissions exiting the roof monitors or roof exhaust fans on the building housing the copper converter department meet the opacity limit as specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) The opacity of any visible emissions exiting the roof monitors or roof exhaust fans on the building housing the copper converter department must not exceed 4 percent as determined by a performance test conducted according to § 63.1450(c).

(ii) The opacity limit in paragraph (d)(4)(i) of this section applies only at those times when a performance test is conducted according to § 63.1450(c). The requirements for compliance with opacity and visible emission standards specified in § 63.6(h) do not apply to this opacity limit.

(5) You must not cause to be discharged to the atmosphere from any Peirce-Smith converter primary hood capture system or Hoboken converter side-flue intake capture system any process off-gas that contains nonsulfuric acid particulate matter in excess of 6.2 mg/dscm as measured using the test methods specified in § 63.1450(b).

(6) You must not cause to be discharged to the atmosphere from any secondary capture system any gases that contain filterable particulate matter in excess of 23 mg/dscm as measured using the test methods specified in § 63.1450(a).

(e) *New copper converter departments.* For each new copper converter department for which construction commenced on or after April 20, 1998, the use of batch copper converters is prohibited. For each new copper converter department which will contain a copper converter other than a batch converter (such as a continuous converter), you must comply with the emission limitation and work practice standards in paragraphs (e)(1) and (2) of this section.

(1) You must not cause to be discharged to the atmosphere from any combination of stacks or other vents any captured process off-gas that contains filterable particulate matter greater than a daily (24-hour) average of 0.031 pounds of particulate matter per ton of copper concentrate feed charged to the smelting vessel as measured using the test methods specified in § 63.1450(a).

(2) You must operate a capture system that collects the gases and fumes released from converting vessels and conveys the collected gas stream to a control device.

(f) *New and existing anode refining departments.* Except as provided in paragraph (f)(1) of this section, for each new and existing anode refining department, you must comply with the emission limitation and work practice standards in paragraphs (f)(2) and (3) of this section.

(1) If the anode refining department process exhaust gases are combined with the Hoboken converter process fugitive capture system, you must demonstrate compliance with the emission limitation and work practice standards in paragraph (g) of this section.

(2) For each new and existing anode refining department, you must not discharge to the atmosphere captured process exhaust gases from the anode refining furnaces containing filterable particulate matter emissions in excess of 5.8 mg/dscm as measured using the test methods specified in § 63.1450(a).

(3) You must operate a capture system that collects the process off-gases and fumes released from the anode refining department and convey the collected gas stream to a control device.

(g) *Existing combined anode refining department and Hoboken converter process fugitive capture system.* For each new and existing anode refining department and Hoboken converter process fugitive capture system, you must comply with the emission limitation and work practice standards in paragraphs (g)(1) through (3) of this section.

(1) You must not discharge to the atmosphere gases from the combination of the anode refining department and Hoboken converter process fugitive capture system filterable particulate matter emissions in excess of 4.1 mg/dscm as measured using the test methods specified in § 63.1450(a).

(2) You must operate a Hoboken converter process fugitive capture system that collects the process off-gases and fumes released from the copper converter department.

(3) You must operate a capture system that collects the process off-gases and fumes released from the anode refining department and convey the collected gas stream to a control device.

(h) *New and existing sources of process fugitive gases from the roofline vents associated with the smelting vessels, the slag cleaning vessels, copper converter department, and the anode refining department.* You must not discharge to the atmosphere process fugitive gases from any combination of new and existing roofline vents associated with the smelting vessels, slag cleaning vessels, copper converter departments and the anode refining departments containing filterable particulate matter emissions in excess of 6.3 lb/hr as measured using the test methods specified in § 63.1450(e).

(i) *Baghouses.* For each baghouse applied to meet any filterable particulate matter emission limit in paragraphs (a) through (h) of this section, you must operate the baghouse such that the bag leak detection system does not alarm for more than 5 percent of the total operating time in any semiannual reporting period.

(j) *Venturi wet scrubbers.* For each venturi wet scrubber applied to meet any filterable particulate matter emission limit in paragraphs (a) through (h) of this section, you must comply with the site-specific operating limit(s) of maintaining the hourly average pressure drop and scrubber water flow rate established during the initial or subsequent performance test in accordance with § 63.1450(a)(4).

(k) *Other control devices.* For each control device other than a baghouse or venturi wet scrubber applied to meet any filterable particulate matter emission limit in paragraphs (a) through (h) of this section, you must operate the control device as specified in paragraphs (k)(1) and (2) of this section.

(1) You must select one or more operating parameters, as appropriate for the control device design, that can be used as representative and reliable indicators of the control device operation.

(2) You must maintain the hourly average value for each of the selected parameters at or above the minimum level or at or below the maximum level, as appropriate for the selected parameter, established during the initial or subsequent performance test in accordance with § 63.1450(a)(5).

(l) *Existing source mercury emissions.* You must not discharge exhaust gases to the atmosphere through any combination of stacks or other vents from copper concentrate dryers, copper converter department, the anode refining department, slag cleaning vessel and smelting vessels containing mercury emissions in excess of 0.033 lb/hr for existing sources as measured by the test methods in § 63.1450(d).

(m) *New source mercury emissions.* You must not discharge exhaust gases to the atmosphere through any combination of stacks or other vents from the copper concentrate dryers, copper converter department, the anode refining department, slag cleaning vessel and smelting vessels containing mercury emissions in excess of 0.00097 lb/hr for new sources as measured by the test methods in § 63.1450(d).

(n) *Control devices for mercury.* For each control device applied to meet the mercury emission limit in paragraph (l) or (m) of this section, you must operate the control device as specified in paragraphs (n)(1) and (2) of this section.

(1) You must select one or more operating parameters, as appropriate for the control device design, that can be used as representative and reliable indicators of the control device operation.

(2) You must maintain the hourly average value for each of the selected parameters at or above the minimum level or at or below the maximum level, as appropriate for the selected parameter, established during the initial or subsequent performance test in accordance with § 63.1450(d)(3).

(o) *New and existing sources of benzene, toluene, chlorine, hydrogen chloride, polycyclic aromatic hydrocarbons excluding naphthalene, naphthalene, and dioxins/furans emissions.* You must not discharge exhaust gases to the atmosphere through any combination of stacks or other vents from the copper concentrate dryers, copper converter department, the anode refining department, slag cleaning vessels and the smelting vessels in excess the emission limits in table 2 to this subpart as measured by the test methods in § 63.1450(f).

(p) *Existing sources of process fugitive gases from the combination of roofline vents associated with the Peirce-Smith converter department, Inco flash furnace, and anode refining department.* For any combination of new and existing roofline vents associated with the Peirce-Smith converter department, Inco flash furnace, and anode refining department, you must comply with the emission limitation and design standards in paragraph (p)(1) and (2) of this section.

(1) *Roofline emission limit for the Peirce-Smith converter department, Inco flash furnace, and anode refining department.* You must not discharge to the atmosphere process fugitive gases from any combination of existing roofline vents associated with the Peirce-Smith copper converter department, Inco flash furnace, and the anode refining department containing lead emissions in excess of 0.326 lb/hr as measured using the test methods specified in § 63.1450(g).

(2) *Design standards for the Peirce-Smith converter department, Inco flash furnace, and anode refining department.* You must comply with design standards in paragraphs (p)(2)(i) through (iii) of this section at all times when the primary copper smelter is operating, except as provided herein.

(i) *Flash furnace area capture system.* Operate hooding and interceptor walls with a design evacuation rate of at least 50,000 cfm hourly average to capture fugitive emissions from the flash furnace area, matte tapping and slag skimming areas, and route emissions to a control device whenever the flash furnace is in operation except for brief periods when slag is being returned to the flash furnace using the slag return launder.

(ii) *Fuming ladle capture system.* Operate hood and interceptor walls with a design evacuation rate of at least 40,000 cfm to capture fugitive emissions from fuming ladles in the converter aisle and material transfer areas, and route emissions to a control device whenever a fuming ladle is detected.

(iii) *Anode furnace secondary hood capture and control system.* Operate a secondary hood around each in-use anode furnace to capture process fugitive emissions and route emissions to a control device. The design evacuation rate for the total system of all anode furnace secondary hoods shall be at least 150,000 cfm hourly average.

(q) *Bypass stack work practice standards.* When using the bypass stack for planned maintenance of control devices and processes, the work practice standard is applicable for the bypass stack for the duration of the planned maintenance. You must comply with work practice standards in paragraphs (q)(1) through (3) of this section.

(1) In the case of planned control device or process maintenance, feed to the smelting vessel must cease; power to the electric furnace must be lowered, and a crust allowed to form on the surface of the slag; the operation of the converters must cease and the converters rolled out; and the operation of the anode vessels must cease.

(2) If the fan to the anode refining point source baghouse is functioning, then the residual process gases must be redirected to the control device. If the process gas from a device being maintenanced can be rerouted to a different control device instead of the bypass stack, it must be redirected to the control device. Control devices must be used until emissions are minimized.

(3) If there is a shutdown or emergency shutdown event, the control devices should continue to run until process emissions cease. If the control devices are shut down before the process emissions cease and the bypass stack is used to vent the process gas to the atmosphere, there will be a violation of the emission and work practice standards.

§ 63.1445 What work practice standards must I meet for my fugitive dust sources?

(a) You must control particulate matter emissions from fugitive dust sources at your primary copper smelter by operating according to a written fugitive dust control plan that has been approved by the Administrator or approved authority under 40 CFR part 70 or 71. For the purpose of complying with this paragraph (a) you must submit a fugitive dust control plan which addresses the fugitive dust sources specified in paragraph (b) of this section and includes the information specified in paragraph (c) of this section on the schedule provided in paragraphs (e) and (f) of this section.

(b) Before November 12, 2024, your fugitive dust control plan must address each of the fugitive dust emission sources listed in paragraphs (b)(1) through (6), except paragraphs (b)(1)(i) and (ii), of this section that are located at your primary copper smelter. On or after November 12, 2024, your fugitive dust control plan must address each of the fugitive dust emission sources listed in paragraphs (b)(1) through (7) of this section that are located at your primary copper smelter.

(1) On-site roadways used by trucks or other motor vehicles (e.g., front-end loaders) when transporting bulk quantities of fugitive dust materials. Paved roads and parking areas that are not used by these vehicles do not need to be included in the plan (e.g., employee and visitor parking lots).

(i) You must conduct routine cleaning of paved roads with a sweeper, vacuum or wet broom (in accordance with applicable recommendations by the manufacturer of the street sweeper, vacuum, or wet broom), with such cleaning to occur no less frequently than on a daily basis unless the roads have sufficient surface moisture such that fugitive dust is not generated.

(ii) Chemical dust suppressants will be applied not less frequently than once per month at slag haul roads and not less frequently than every 6 weeks on all other unpaved roads unless the roads have sufficient surface moisture such that fugitive dust is not generated.

(2) Unloading of fugitive dust materials from trucks or railcars.

(3) Outdoor piles used for storage of fugitive dust materials.

(4) Bedding areas used for blending copper concentrate and other feed constituents.

(5) Each transfer point in conveying systems used to transport fugitive dust materials. These points include, but are not limited to, transfer of material from one conveyor belt to another and transfer of material to a hopper or bin.

(6) Other site-specific sources of fugitive dust emissions that the Administrator or delegated authority under 40 CFR part 70 or 71 designate to be included in your fugitive dust control plan.

(7) The cargo compartment of all trucks or other motor vehicles (e.g., front-end loaders) when transporting bulk quantities of fugitive dust materials must be maintained to ensure:

(i) The floor, sides, and/or tailgate(s) are free of holes or other openings.

(ii) All loads of trucks containing copper concentrate arriving at the facility are covered with a tarp to prevent spills and fugitive emissions.

(iii) Trucks are loaded only to such a level as to prevent spillage over the side.

(iv) A speed limit of 15 mph is required.

(v) All dust producing material internally transferred or moved by truck at the facility is covered with a tarp to prevent spills and fugitive emissions.

(c) Your fugitive dust control plan must describe the control measures you use to control fugitive dust emissions from each source addressed in the plan, as applicable and appropriate for your site conditions. Examples of control measures include, but are not limited to, locating the source inside a building or other enclosure, installing and operating a local hood capture system over the source and venting the captured gas stream to a control device, placing material stockpiles below grade, installing wind screens or wind fences around the source, spraying water on the source as weather conditions require, applying appropriate dust suppression agents on the source, or combinations of these control measures.

(d) The requirement for you to operate according to a written fugitive dust control plan must be incorporated in your operating permit that is issued by the approved authority under 40 CFR part 70 or 71. A copy of your fugitive dust control plan must be sent to the approved authority under 40 CFR part 70 or 71 on or before the compliance date for your primary copper smelter, as specified in § 63.1443 or paragraph (b) of this section.

(e) For any element of the fugitive dust control plan that requires new construction at the facility, the owner or operator shall complete such construction, in accordance with the specifications and schedule set forth in the approved fugitive dust control plan.

(f) The fugitive dust control plan must be reviewed, updated (if necessary), and then submitted to the approved permitting authority under 40 CFR part 70 or 71 with each application for the title V operating permit renewal and with each permit application for the construction or modification of lead-bearing fugitive dust generating sources. On or after November 12, 2024, the owner or operator must submit a copy fugitive dust plan in PDF format to the EPA via Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov*) following the procedure specified in §§ 63.1455(e) and 63.9(k).

§ 63.1446 What alternative emission limitation may I meet for my combined gas streams?

(a) For situations where you combine gas streams from two or more affected sources for discharge to the atmosphere through a single vent, you may choose to meet the requirements in paragraph (b) of this section as an alternative to complying with the individual filterable particulate matter emission limits specified in § 63.1444 that apply to you. This alternative emission limit for a combined gas stream may be used for any combination of the affected source gas steams specified in paragraphs (a)(1) through (6) of this section.

(1) Gas stream discharged from a copper concentrate dryer vent that would otherwise be subject to § 63.1444(a)(1) or (2);

(2) Gas stream discharged from a smelting vessel capture system that would otherwise be subject to § 63.1444(b)(2)(ii);

(3) Process off-gas stream discharged from a slag cleaning vessel that would otherwise be subject to § 63.1444(c)(2);

(4) Gas stream discharged from a slag cleaning vessel capture system that would otherwise be subject to § 63.1444(c)(3)(ii);

(5) Gas stream discharged from an existing batch copper converter secondary capture system that would otherwise be subject to § 63.1444(d)(6); and

(6) Gas stream discharged from anode refining departments that would otherwise be subject to § 63.1444(f)(2).

(b) You must meet the requirements specified in paragraphs (b)(1) and (2) of this section for the combined gas stream discharged through a single vent.

(1) For each combined gas stream discharged through a single vent, you must not cause to be discharged to the atmosphere any gases that contain filterable particulate matter in excess of the emission limit calculated using the procedure in paragraph (b)(2) of this section and measured using the test methods specified in § 63.1450(a).

(2) You must calculate the alternative filterable particulate matter emission limit for your combined gas stream using equation 1 to this paragraph (b)(2). The volumetric flow rate value for each of the individual affected source gas streams that you use for equation 1 (i.e., the flow rate of the gas stream discharged from the affected source but before this gas stream is combined with the other gas streams) is to be the average of the volumetric flow rates measured using the test method specified in § 63.1450(a)(1)(ii):

Equation 1 to Paragraph (b)(2)

$$E_{Alt} = \frac{E_d Q_d + E_{sv} Q_{sv} + E_{scvp} Q_{scvp} + E_{scvf} Q_{scvf} + E_{cc} Q_{cc} + E_{ard} Q_{ard}}{Q_d + Q_{sv} + Q_{scvp} + Q_{scvf} + Q_{cc} + Q_{ard}}$$

Where:

E_{Alt} = Alternative filterable particulate matter emission limit for the combined gas stream discharged to atmosphere through a single vent (mg/dscm);

E_d = Filterable particulate matter emission limit applicable to copper concentrate dryer as specified in § 63.1444(a)(1) or (2) (mg/dscm);

Q_d = Copper concentrate dryer exhaust gas stream volumetric flow rate before being combined with other gas streams (dscm/hr);

Esv = Filterable particulate matter emission limit for smelting vessel capture system as specified in § 63.1444(b)(2)(ii) (mg/dscm);

Qsv = Smelting vessel capture system exhaust gas stream volumetric flow rate before being combined with other gas streams (dscm/hr);

Escvp = Filterable particulate matter emission limit for slag cleaning vessel process off-gas as specified in § 63.1444(c)(2) (mg/dscm);

Qscvp = Slag cleaning vessel process off-gas volumetric flow rate before being combined with other gas streams (dscm/hr);
Escvf = Filterable particulate matter emission limit for slag cleaning vessel capture system as specified in § 63.1444(c)(3)(ii) (mg/dscm);
Qscvf = Slag cleaning vessel capture system exhaust gas stream volumetric flow rate before being combined with other gas streams (dscm/hr);
Ecc = Filterable particulate emission limit for the existing batch copper converter secondary capture system as specified in § 63.1444(d)(6) (mg/dscm);
Qcc = Batch copper converter capture system exhaust gas stream volumetric flow rate before being combined with other gas streams (dscm/hr);
E_{ard} = Filterable particulate matter emission limit for the anode refining department as specified in § 63.1444(f)(2); and
Q_{ard} = Anode refining department exhaust gas stream volumetric flow rate before being combined with other gas streams (dscm/hr).

(c) For each baghouse applied to meet any filterable particulate matter emission limit in paragraph (b) of this section, you must operate the baghouse such that the bag leak detection system does not alarm for more than 5 percent of the total operating time in any semiannual reporting period.

(d) For each venturi wet scrubber applied to meet any filterable particulate matter emission limit in paragraph (b) of this section, you must maintain the hourly average pressure drop and scrubber water flow rate at or above the minimum levels established during the initial or subsequent performance test in accordance with § 63.1450(a)(4).

(e) For each control device other than a baghouse or venturi wet scrubber applied to meet any filterable particulate matter emission limit in paragraph (b) of this section, you must operate the control device as specified in paragraphs (e)(1) and (2) of this section.

(1) You must select one or more operating parameters, as appropriate for the control device design, that can be used as representative and reliable indicators of the control device operation.

(2) You must maintain the hourly average value for each of the selected parameters at or above the minimum level or at or below the maximum level, as appropriate for the selected parameter, established during the initial or subsequent performance test in accordance with § 63.1450(a)(5).

§ 63.1447 What are my operation and maintenance requirements?

(a) Before November 12, 2024, as required by § 63.6(e)(1)(i), you must always operate and maintain your affected source, including air pollution control and monitoring equipment, in a manner consistent with good air pollution control practices for minimizing emissions at least to the levels required by this subpart. On or after November 12, 2024, at all times, you must maintain and operate 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 or 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.

(b) You must prepare and operate at all times according to a written operation and maintenance plan for each capture system and control device subject to standards in § 63.1444 or § 63.1446. The plan must address the requirements in paragraphs (b)(1) through (4) of this section as applicable to the capture system or control device.

(1) *Preventative maintenance.* You must perform preventative maintenance for each capture system and control device according to written procedures specified in your operation and maintenance plan. The procedures must include a preventative maintenance schedule that is consistent with the manufacturer's instructions for routine and long-term maintenance.

(2) *Capture system inspections.* You must conduct monthly inspections of the equipment components of the capture system that can affect the performance of the system to collect the gases and fumes emitted from the affected source (e.g., hoods, exposed ductwork, dampers, fans) according to written procedures specified in your operation and maintenance plan. The inspection procedure must include the requirements in paragraphs (b)(2)(i) through (iii) of this section as applicable to the capture system or control device.

(i) Observations of the physical appearance of the equipment to confirm the physical integrity of the equipment (e.g., verify by visual inspection no holes in ductwork or hoods, no flow constrictions caused by dents, or accumulated dust in ductwork).

(ii) Inspection, and if necessary testing, of equipment components to confirm that the component is operating as intended (e.g., verify by appropriate measures that flow or pressure sensors, damper plates, automated damper switches and motors are operating according to manufacture or engineering design specifications).

(iii) In the event that a defective or damaged component is detected during an inspection, you must initiate corrective action according to written procedures specified in your operation and maintenance plan to correct the defect or deficiency as soon as practicable.

(3) *Copper converter department capture system operating limits.* You must establish, according to the requirements in paragraph (b)(3)(i) through (iii) of this section, operating limits for the capture system that are representative and reliable indicators of the performance of capture system when it is used to collect the process off-gas vented from batch copper converters during blowing.

(i) Select operating limit parameters appropriate for the capture system design that are representative and reliable indicators of the performance of the capture system when it is used to collect the process off-gas vented from batch copper converters during blowing. At a minimum, you must use appropriate operating limit parameters that indicate the level of the ventilation draft and the damper position settings for the capture system when operating to collect the process off-gas from the batch copper converters during blowing. Appropriate operating limit parameters for ventilation draft include, but are not limited to, volumetric flow rate through each separately ducted hood, total volumetric flow rate at the inlet to control device to which the capture system is vented, fan motor amperage, or static pressure. Any parameter for damper position setting may be used that indicates the duct damper position relative to the fully open setting.

(ii) For each operating limit parameter selected in paragraph (b)(3)(i) of this section, designate the value or setting for the parameter at which the capture system operates during batch copper converter blowing. If your blister copper production operations allow for more than one batch copper converter to be operating simultaneously in the blowing mode, designate the value or setting for the parameter at which the capture system operates during each possible batch copper converter blowing configuration that you may operate at your smelter (*i.e.,* the operating limits with one converter blowing, with two converters blowing, with three converters blowing, as applicable to your smelter).

(iii) Include documentation in the plan to support your selection of the operating limits established for the capture system. This documentation must include a description of the capture system design, a description of the capture system operation during blister copper production, a description of each selected operating limit parameter, a rationale for why you chose the parameter, a description of the method used to monitor the parameter according to the requirements in § 63.1452(a), and the data used to set the value or setting for the parameter for each of your batch copper converter configurations.

(4) *Baghouse leak detection corrective actions.* In the event a bag leak detection system alarm is triggered, you must initiate corrective action according to written procedures specified in your operation and maintenance plan to determine the cause of the alarm within 1 hour of the alarm, initiate corrective action to correct the cause of the problem within 24 hours of the alarm, and complete the corrective action as soon as practicable. Corrective actions may include, but are not limited to, the activities listed in paragraphs (b)(3)(i) through (vi) of this section.

(i) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in 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 repair the bag leak detection system.

(vi) Shutting down the process producing the particulate emissions.

§ 63.1448 What are my general requirements for complying with this subpart?

(a) Before November 12, 2024, you must be in compliance with the emission limitations, work practice standards, and operation and maintenance requirements in this subpart at all times, except during periods of startup, shutdown, and malfunction as defined in § 63.2. On or after November 12, 2024, you must be in compliance with the emission limitations, work practice standards, design standards, and operation and maintenance requirements in this subpart at all times.

(b) During the period between the compliance date specified for your affected source in § 63.1443, and the date upon which continuous monitoring systems have been installed and certified and any applicable operating limits have been set, you must maintain a log detailing the operation and maintenance of the process and emissions control equipment.

(c) Before November 12, 2024, you must develop a written startup, shutdown, and malfunction plan according to the provisions in § 63.6(e)(3). For affected sources, a startup, shutdown, and malfunction plan is not required on or after November 12, 2024.

§ 63.1449 By what dates must I conduct performance tests or other initial compliance demonstrations?

(a) As required in § 63.7(a)(2), you must conduct a performance test within 180 calendar days of the compliance date that is specified in § 63.1443 for your affected source to demonstrate initial compliance with each emission and opacity limit in §§ 63.1444 and 63.1446 that applies to you.

(b) For each work practice standard and operation and maintenance requirement that applies to you where initial compliance is not demonstrated using a performance test or opacity observation, you must demonstrate initial compliance within 30 calendar days after the compliance date that is specified for your affected source in § 63.1443.

§ 63.1450 What test methods and other procedures must I use to demonstrate initial compliance with the emission limitations and design standards?

(a) *Filterable particulate matter emission limits.* Before November 12, 2024, you must conduct each performance test to determine compliance with the filterable particulate matter emission limits in § 63.1444 or § 63.1446 that apply to you according to the requirements for representative test conditions specified in § 63.7(e)(1) and using the test methods and procedures in paragraphs (a)(1) through (5) of this section. On or after November 12, 2024, you must conduct each performance test to determine compliance with the filterable particulate matter emission limits in § 63.1444 or § 63.1446 that apply to you according to the requirements for representative test conditions specified in paragraph (a)(6) of this section and using the test methods and procedures in paragraphs (a)(1) through (5) of this section.

(1) Determine the concentration of filterable particulate matter according to the test methods in appendices A–1 through A–8 to 40 CFR part 60 as specified in paragraphs (a)(1)(i) through (v) of this section.

(i) Method 1 to select sampling port locations and the number of traverse points. Sampling ports must be located at the outlet of the control device and prior to any releases to the atmosphere.

(ii) Method 2, 2F, or 2G to determine the volumetric flow rate of the stack gas.

(iii) Method 3, 3A, or 3B to determine the dry molecular weight of the stack gas. The ANSI/ASME PTC 19–10–1981 Part 10 (incorporated by reference, see § 63.14) is an acceptable alternative to EPA Method 3B manual portion only but not the instrumental portion.

(iv) Method 4 to determine the moisture content of the stack gas.

(v) Method 5, 5D, or 17, as applicable, to determine the concentration of filterable particulate matter.

(2) As an alternative to using the applicable method specified in paragraph (a)(1)(v) of this section, you may determine filterable particulate matter emissions from the control device using Method 29 in appendix A–8 to 40 CFR part 60 provided that you follow the procedures and precautions prescribed in Method 29. If the control device is a positive pressure baghouse, you must also follow the measurement procedure specified in sections 8.1 through 8.3 of Method 5D in appendix A–3 to 40 CFR part 60.

(3) You must conduct three separate test runs for each performance test. Each test run must have a minimum sampling time of 60 minutes and a minimum sampling volume of 0.85 dscm. For the purpose of determining compliance with the applicable filterable particulate matter emission limit, the arithmetic mean of the results for the three separate test runs is used.

(4) For a venturi wet scrubber applied to emissions from an affected source and subject to emission limits and work practice standards in § 63.1444(j) or § 63.1446(d) for pressure drop and scrubber water flow rate, you must establish site-specific operating limits according to the procedures in paragraphs (a)(4)(i) and (ii) of this section.

(i) Using the continuous parameter monitoring system (CPMS) required in § 63.1452, measure and record the pressure drop and scrubber water flow rate during each run of the particulate matter performance test.

(ii) Compute and record the hourly average pressure drop and scrubber water flow rate for each individual test run. Your operating limits are the lowest average pressure drop and scrubber water flow rate value in any of the three runs that meet the applicable emission limit.

(5) For a control device other than a baghouse or venturi wet scrubber applied to emissions from an affected source and subject to work practice standards and emission limit(s) in § 63.1444(k) or § 63.1446(e) for appropriate, site-specific operating parameters that are representative and reliable indicators of the control device performance, you must establish a site-specific operating limit(s) according to the procedures in paragraphs (a)(5)(i) through (iv) of this section.

(i) Select one or more operating parameters, as appropriate for the control device design, that can be used as representative and reliable indicators of the control device operation.

(ii) Using the CPMS required in § 63.1452, measure and record the selected operating parameters for the control device during each run of the filterable particulate matter performance test.

(iii) Compute and record the hourly average value for each of the selected operating parameters for each individual test run. Your operating limits are the lowest value or the highest value, as appropriate for the selected operating parameter, measured in any of the three runs that meet the applicable emission limit.

(iv) You must prepare written documentation to support your selection of the operating parameters used for the control device. This documentation must include a description of each selected parameter, a rationale for why you chose the parameter, a description of the method used to monitor the parameter, and the data recorded during the performance test and used to set the operating limit(s).

(6) You must conduct each performance test that applies to your affected source under normal operating conditions of the affected source. The owner or operator may not conduct performance tests during periods of malfunction. The use of the bypass stack during a performance test of the process shall invalidate the performance test. 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 such conditions represent the entire range of normal operation, including operational conditions for maximum emissions if such emissions are not expected during maximum production. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(b) *Nonsulfuric acid particulate matter emission limits.* Before November 12, 2024, you must conduct each performance test to determine compliance with the nonsulfuric acid particulate matter emission limits in § 63.1444 that apply to you according to the requirements for representative test conditions specified in § 63.7(e)(1) and using the test methods and procedures in paragraphs (b)(1) and (2) of this section. On or after November 12, 2024, you must conduct each performance test to determine compliance with the nonsulfuric acid particulate matter emission limits in § 63.1444 that apply to you according to the requirements for representative test conditions specified in paragraph (b)(4) of this section and using the test methods and procedures in paragraphs (b)(1) through (3) of this section.

(1) Determine the concentration of nonsulfuric acid particulate matter according to the test methods in appendices A–1 through A–8 to 40 CFR part 60 as specified in paragraphs (b)(1)(i) through (v) of this section.

(i) Method 1 to select sampling port locations and the number of traverse points. Sampling ports must be located at the outlet of the control device and prior to any releases to the atmosphere.

(ii) Method 2, 2F, or 2G to determine the volumetric flow rate of the stack gas.

(iii) Method 3, 3A, or 3B to determine the dry molecular weight of the stack gas. The ANSI/ASME PTC 19–10–1981 Part 10 (incorporated by reference, see § 63.14) is an acceptable alternative to EPA Method 3B manual portion only but not the instrumental portion.

(iv) Method 4 to determine the moisture content of the stack gas.

(v) Method 5B to determine the nonsulfuric acid particulate matter emissions.

(2) You must conduct three separate test runs for each performance test. Each test run must have a minimum sampling time of 240 minutes and a minimum sampling volume of 3.4 dscm. For the purpose of determining compliance with the nonsulfuric acid particulate matter emission limit, the arithmetic mean of the results for the three separate test runs is used.

(3) For a control device applied to emissions from an affected source and subject to work practice standards and emission limit(s) in § 63.1444(i), (j), or (k) or § 63.1446(e) for appropriate, site-specific operating parameters that are representative and reliable indicators of the control device performance, you must establish a site-specific operating limit(s) according to the procedures in paragraphs (a)(5)(i) through (iv) of this section.

(4) You must conduct each performance test that applies to your affected source under normal operating conditions of the affected source. The owner or operator may not conduct performance tests during periods of malfunction. The use of the bypass stack during a performance test of the process shall invalidate the performance test. 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 such conditions represent the entire range of normal operation, including operational conditions for maximum emissions if such emissions are not expected during maximum production. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(c) *Copper converter department capture system opacity limit.* You must conduct each performance test to determine compliance with the opacity limit in § 63.1444 using the test methods and procedures in paragraphs (c)(1) through (9) of this section and during the particulate matter performance test.

(1) You must conduct the performance test during the period when the primary copper smelter is operating under conditions representative of the smelter's normal blister copper production rate. You may not conduct a performance test during a malfunction. Before conducting the performance test, you must prepare a written test plan specifying the copper production conditions to be maintained throughout the opacity observation period and including a copy of the written documentation you have prepared according to paragraph (a)(3) of this section to support the established operating limits for the copper converter department capture system. You must submit a copy of the test plan for review and approval by the Administrator or delegated authority. During the observation period, you must collect appropriate process information and copper converter department capture system operating information to prepare documentation sufficient to verify that all opacity observations were made during the copper production and capture system operating conditions specified in the approved test plan.

(2) You must notify the Administrator or delegated authority before conducting the opacity observations to allow the Administrator or delegated authority the opportunity to have authorized

representatives attend the test. Written notification of the location and scheduled date for conducting the opacity observations must be received by the Administrator on or before 30 calendar days before this scheduled date.

(3) You must gather the data needed for determining compliance with the opacity limit using qualified visible emission observers and process monitors as described in paragraphs (c)(3)(i) and (ii) of this section.

(i) Opacity observations must be performed by a sufficient number of qualified visible emission observers to obtain two complete concurrent sets of opacity readings for the required observation period. Each visible emission observer must be certified as a qualified observer by the procedure specified in section 3 of Method 9 in appendix A–4 to 40 CFR part 60. The entire set of readings during the required observation period does not need to be made by the same two observers. More than two observers may be used to allow for substitutions and provide for observer rest breaks. The owner or operator must obtain proof of current visible emission reading certification for each observer. ASTM D7520–16 (incorporated by reference, see § 63.14) is an acceptable alternative to EPA Method 9 with the specified conditions in paragraphs (c)(3)(i)(A) through (E) of this section.

(A) During the digital camera opacity technique (DCOT) certification procedure outlined in section 9.2 of ASTM D7520–16, you or the DCOT vendor must present the plumes in front of various backgrounds of color and contrast representing conditions anticipated during field use such as blue sky, trees, and mixed backgrounds (clouds and/or a sparse tree stand).

(B) You must also have standard operating procedures in place including daily or other frequency quality checks to ensure the equipment is within manufacturing specifications as outlined in section 8.1 of ASTM D7520–16.

(C) You must follow the record keeping procedures outlined in § 63.10(b)(1) for the DCOT certification, compliance report, data sheets, and all raw unaltered JPEGs used for opacity and certification determination.

(D) You or the DCOT vendor must have a minimum of four (4) independent technology users apply the software to determine the visible opacity of the 300 certification plumes. For each set of 25 plumes, the user may not exceed 15% opacity of anyone reading and the average error must not exceed 7.5% opacity.

(E) This approval does not provide or imply a certification or validation of any vendor's hardware or software. The onus to maintain and verify the certification and/or training of the DCOT camera, software and operator in accordance with ASTM D7520–16 and this letter is on the facility, DCOT operator, and DCOT vendor.

(ii) A person (or persons) familiar with the copper production operations conducted at the smelter must serve as the indoor process monitor. The indoor process monitor is stationed at a location inside the building housing the batch copper converters such that he or she can visually observe and record operations that occur in the batch copper converter aisle during the times that the visible emission observers are making opacity readings. More than one indoor process monitor may be used to allow for substitutions and provide for rest breaks.

(4) You must make all opacity observations using Method 9 in appendix A–4 to 40 CFR part 60 and following the procedures described in paragraphs (c)(4)(i) and (ii) of this section. ASTM D7520–16 (incorporated by reference, see § 63.14) is an acceptable alternative to EPA Method 9 with the specified conditions in paragraphs (c)(3)(i)(A) through (E) of this section.

(i) Each visible emission observer must make his or her readings at a position from the outside of the building that houses the copper converter department such that the observer's line-of-sight is approximately perpendicular to the longer axis of the converter building, and the observer has an unobstructed view of the building roof monitor sections or roof exhaust fan outlets that are positioned over each of the batch copper converters inside the building. Opacity readings can only be made during those times when the observer's position meets the sun orientation and other conditions specified in section 2.1 of Method 9 in appendix A–4 to 40 CFR part 60.

(ii) At 15-second intervals, each visible emission observer views the building roof monitor sections or roof exhaust fan outlets that are positioned over each of the batch copper converters inside the building and reads the opacity of the visible plumes. If no plume is visible, the observer records zero as the opacity value for the 15-second interval. In situations when it is possible for an observer to distinguish two or more visible emission plumes from the building roof monitor sections or roof exhaust fan outlets, the observer must identify, to the extent feasible, the plume having the highest opacity and record his or her opacity reading for that plume as the opacity value for the 15-second interval.

(5) You must make opacity observations for a period of sufficient duration to obtain a minimum of 120 1-minute intervals during which at least one copper converter is blowing and no interferences have occurred from other copper production events, as specified in paragraph (c)(7) of this section, which generate visible emissions inside the building that potentially can interfere with the visible emissions from the converter capture systems as seen by the outside observers. To obtain the required number of 1-minute intervals, the observation period may be divided into two or more segments performed on the same day or on different days if conditions prevent the required number of opacity readings from being obtained during one continuous time period. Examples of these conditions include, but are not limited to, changes in the sun's orientation relative to visible emission observers' positions such that the conditions in Method 9 in appendix A–4 to 40 CFR part 60 are no longer met or an unexpected thunderstorm. If the total observation period is divided into two or more segments, all opacity observations must be made during the same set of copper production conditions described in your approved test plan as required by paragraph (c)(1) of this section.

(6) You must gather indoor process information during all times that the visible emission observers are making opacity readings outside the building housing the copper converter department. The indoor process monitor must continually observe the operations occurring in the copper converter department and prepare a written record of his or her observations using the procedure specified in paragraphs (c)(6)(i) through (iv) of this section.

(i) At the beginning of each observation period or segment, the clock time setting on the watch or clock to be used by the indoor process monitor must be synchronized with the clock time settings for the timepieces to be used by the outdoor opacity observers.

(ii) During each period or segment when opacity readings are being made by the visible emission observers, the indoor process monitor must continuously observe the operations occurring in the copper converter department and record his or her observations in a log book, on data sheets, or other type of permanent written format.

(iii) When a batch copper converter is blowing, a record must be prepared for the converter that includes, but is not limited to, the clock times for when blowing begins and when blowing ends and the converter blowing rate. This information may be recorded by the indoor process monitor or by a separate, automated computer data system.

(iv) The process monitor must record each event other than converter blowing that occurs in or nearby the converter aisle that he or she observes to generate visible emissions inside the building. The recorded entry for each event must include, but is not limited to, a description of the event and the clock times when the event begins and when the event ends.

(7) You must prepare a summary of the data for the entire observation period using the information recorded during the observation period by the outdoor visible emission observers and the indoor process monitor and the procedure specified in paragraphs (c)(7)(i) through (iv) of this section.

(i) Using the field data sheets, identify the 1-minute clock times for which a total of eight opacity readings were made and recorded by both observers at 15-second intervals according to the test procedures (i.e., a total of four opacity values have been recorded for the 1-minute interval by each of the two observers). Calculate the average of the eight 15-second interval readings recorded on the field data sheets by the two observers during the clock time minute interval (add the four consecutive 15-second interval opacity readings made by Observer A during the specified clock time minute, plus the four consecutive 15-second interval opacity readings made by Observer B during the same clock time minute, and divide the resulting total by eight). Record the clock time and the opacity average for the 1-minute interval on a data summary sheet. Figure 1 to this subpart shows an example of the format for the data summary sheet you may use, but are not required to use.

(ii) Using the data summary sheets prepared according to paragraph (c)(7)(i) of this section and the process information recorded according to paragraph (c)(6)(iii) of this section, identify those 1-minute intervals for which at least one of the batch copper converters was blowing.

(iii) Using the data summary sheets prepared according to paragraph (c)(7)(ii) of this section and the process information recorded according to paragraph (c)(6)(iv) of this section, identify the 1-minute intervals during which at least one copper converter was blowing but none of the interference events listed in paragraphs (c)(7)(iii)(A) through (F) of this section occurred. Other ancillary activities not listed but conducted in or adjacent to the converter aisle during the opacity observations are not considered to be interference events (e.g., converter aisle cleaning, placement of smoking ladles or skulls on the converter aisle floor).

(A) Charging of copper matte, reverts, or other materials to a batch copper converter;

(B) Skimming slag or other molten materials from a batch copper converter;

(C) Pouring of blister copper or other molten materials from a batch copper converter;

(D) Return of slag or other molten materials to the flash smelting vessel or slag cleaning vessel;

(E) Roll-out or roll-in of the batch copper converter; or

(F) Smoke and fumes generated inside the converter building by operation of the smelting vessel, the slag cleaning vessel (if used), anode refining and casting processes that drift into the copper converter department.

(iv) Using the data summary sheets prepared according to paragraph (c)(7)(iii) of this section, up to five 1-minute intervals following an interference event may be eliminated from data used for the compliance determination calculation specified in paragraph (c)(8) of this section by applying a time delay factor. The time delay factor must be a constant number of minutes not to exceed 5 minutes that is added to the clock time recorded when cessation of the interference event occurs. The same time delay factor must be used for all interference events (i.e., a constant time delay factor for the smelter of 1 minute, 2 minutes, 3 minutes, 4 minutes, or 5 minutes). The number of minutes to be used for the time delay factor is determined based on the site-specific equipment and converter building configuration. An explanation of the rationale for selecting the value used for the time delay factor must be prepared and included in the test report.

(8) You must use the data summary prepared in paragraph (c)(7) of this section to calculate the average opacity value for a minimum of 120 1-minute intervals during which at least one copper converter was blowing with no interference events as determined according to paragraphs (c)(7)(iii) and (iv) of this section. Average opacity is calculated using equation 1 to this paragraph (c)(8):

Equation 1 to paragraph (c)(8)

$$VE_{ave} = \frac{1}{n}\sum_{i=1}^{n} VE_i$$

Where:

VE_{ave} = Average opacity to be used for compliance determination (percent);

n = Total number of 1-minute intervals during which at least one copper converter was blowing with no interference events as determined according to paragraphs (c)(7)(iii) and (iv) of this section (at least 120 1-minute intervals);

i = 1-minute interval "i" during which at least one copper converter was blowing with no interference events as determined according to paragraphs (c)(7)(iii) and (iv) of this section; and

VE_i = Average opacity value calculated for the eight opacity readings recorded during 1-minute interval "i" (percent).

(9) You must certify that the copper converter department capture system operated during the performance test at the operating limits established in your capture system operation and maintenance plan using the procedure specified in paragraphs (c)(9)(i) through (iv) of this section.

(i) Concurrent with all opacity observations, measure and record values for each of the operating limit parameters in your capture system operation and maintenance plan according to the monitoring requirements specified in § 63.1452(a).

(ii) For any dampers that are manually set and remain in the same position at all times the capture system is operating, the damper position must be visually checked and recorded at the beginning and end of each opacity observation period segment.

(iii) Review the recorded monitoring data. Identify and explain any times during batch copper converter blowing when the capture system operated outside the applicable operating limits.

(iv) Certify in your performance test report that during all observation period segments, the copper converter department capture system was operating at the values or settings established in your capture system operation and maintenance plan.

(d) *Mercury emissions.* You must conduct each performance test to determine compliance with the mercury emission limits in § 63.1444 that apply to you according to the requirements for representative test conditions specified in paragraph (d)(4) of this section and using the test methods and procedures in paragraphs (d)(1) through (3) of this section.

(1) Determine the concentration of mercury according to the test methods in appendices A–1 through A–8 to 40 CFR part 60 as specified in paragraphs (d)(1)(i) through (v) of this section.

(i) Method 1 to select sampling port locations and the number of traverse points. Sampling ports must be located at the outlet of the control device and prior to any releases to the atmosphere.

(ii) Method 2, 2F, or 2G to determine the volumetric flow rate of the stack gas.

(iii) Method 3, 3A, or 3B to determine the dry molecular weight of the stack gas. The ANSI/ASME PTC 19–10–1981 Part 10 (incorporated by reference, see § 63.14) is an acceptable alternative to EPA Method 3B manual portion only but not the instrumental portion.

(iv) Method 4 to determine the moisture content of the stack gas.

(v) Method 29, 30A, or 30B, as applicable, to determine the concentration of mercury. You can also use ASTM D6784–16 (incorporated by reference, see § 63.14) or equivalent.

(2) You must conduct three separate test runs for each performance test. Duration of sampling is at least two hours per run. If performing measurements using Method 29 in appendix A–8 to 40 CFR part 60, you must collect a minimum sample volume of 1.7 dscm (60 dscf). For the purpose of determining compliance with the applicable mercury emission limit, the arithmetic mean of the results for the three separate test runs is used.

(3) For a control device or process operating parameter applied to emissions from an affected source and subject to site-specific operating limit(s) in § 63.1444(n) for appropriate, site-specific operating parameters that are representative and reliable indicators of the control device performance, you must establish a site-specific operating limit(s) according to the procedures in paragraphs (d)(3)(i) through (iv) of this section.

(i) Select one or more operating parameters, as appropriate for the control device design or process parameter (*i.e.,* mercury content of concentrate feed), that can be used as representative and reliable indicators of the control device or process operation.

(ii) Using the CPMS required in § 63.1452, measure and record the selected operating parameters for the control device during each run of the mercury performance test.

(iii) Compute and record the hourly average value for each of the selected operating parameters for each individual test run. Your operating limits are the lowest value or the highest value, as appropriate for the selected operating parameter, measured in any of the three runs that meet the applicable emission limit.

(iv) You must prepare written documentation to support your selection of the operating parameters used for the control device. This documentation must include a description of each selected parameter, a rationale for why you chose the parameter, a description of the method used to monitor the parameter, and the data recorded during the performance test and used to set the operating limit(s).

(4) You must conduct each performance test that applies to your affected source under normal operating conditions of the affected source. The owner or operator may not conduct performance tests during periods of malfunction. The use of the bypass stack during a performance test of the process shall invalidate the performance test. 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 such conditions represent the entire range of normal operation, including operational conditions for maximum emissions if such emissions are not expected during maximum production. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(e) *Anode refining department, copper converter department, slag cleaning vessels, and smelting vessels process fugitive roofline vent filterable particulate matter emission limit.* You must conduct each performance test to determine compliance with the roofline vent process fugitive filterable particulate matter emission limits in § 63.1444 that apply to you according to the requirements for representative test conditions specified in paragraph (e)(3) of this section and using the test methods and procedures in paragraphs (e)(1) and (2) of this section.

(1) Determine the concentration of anode refining department, copper converter department, slag cleaning vessels, and smelting vessels process fugitive roofline vent filterable particulate matter according to the test methods in appendices A–1 through A–8 to 40 CFR part 60 as specified in paragraphs (e)(1)(i) through (vi) of this section.

(i) Method 1 to select sampling port locations and the number of traverse points. Sampling ports must be located at the outlet of the control device and prior to any releases to the atmosphere. Use Method 5D, section 8.1.3, Roof Monitor or Monovent, or approved sample locations by EPA Office of Air and Radiation (OAR), OAQPS, Measurement Technology Group or delegated authority.

(ii) Method 2, 2F, or 2G to determine the volumetric flow rate of the stack gas or calibrated anemometer.

(iii) Method 3, 3A, or 3B to determine the dry molecular weight of the stack gas.

The ANSI/ASME PTC 19–10–1981 Part 10 (incorporated by reference, see § 63.14) is an acceptable alternative to EPA Method 3B manual portion only but not the instrumental portion.

(iv) Method 4 to determine the moisture content of the stack gas.

(v) Method 17 to determine in-stack mass volume of the anode refining, converter and smelting process fugitive roof vent filterable particulate matter emissions. Isokinetic calculations are waived due to low flow rates and high variability. Use the filter specified in section 7.2.1 of Method 29. An approved Federal reference method (FRM)/Federal equivalent method (FEM) may be used if it can tolerate the 150 °F temperatures on the roof vents. Tapered element oscillating microbalances (TEOMs) are not appropriate for this sampling. An alternative test method may be requested to EPA OAR, OAQPS, Measurement Technology Group.

(vi) Method 9 to establish opacity as an operating parameter, if appropriate. ASTM D7520–16 (incorporated by reference, see § 63.14) is an acceptable alternative to EPA Method 9 with the specified conditions in paragraphs (c)(3)(i)(A) through (E) of this section.

(2) You must conduct three separate test runs for each performance test. Each test run must have a minimum sampling time of 12 hours. For the purpose of determining compliance with the filterable particulate matter emission limit, the arithmetic mean of the results for the three separate test runs for each roofline vent (i.e., anode refining department, copper converter department, smelting vessels, slag cleaning vessels) is used. The three test run average of the filterable particulate

matter emission rates from each vent should be summed to compare to the emission limit in § 63.1444.

(3) You must conduct each performance test that applies to your affected source under normal operating conditions of the affected source. The owner or operator may not conduct performance tests during periods of malfunction. The use of the bypass stack during a performance test of the process shall invalidate the performance test. 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 such conditions represent the entire range of normal operation, including operational conditions for maximum emissions if such emissions are not expected during maximum production. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(f) *Benzene, toluene, chlorine, hydrogen chloride, polycyclic aromatic hydrocarbons excluding naphthalene, naphthalene, and dioxins/furans emissions.* You must conduct each performance test to determine compliance with the benzene, toluene, chlorine, hydrogen chloride, polycyclic aromatic hydrocarbons excluding naphthalene, naphthalene, and dioxins/furans emission limits in table 2 to this subpart that apply to you according to the requirements for representative test conditions specified in paragraph (f)(8) of this section and using the test methods and procedures in paragraphs (f)(1) through (7) of this section.

(1) Use the test methods in appendices A–1 through A–8 to 40 CFR part 60 as specified in paragraphs (f)(1)(i) through (iv) of this section to select sampling port locations and the number of traverse points and to determine the volumetric flow rate, dry molecular weight, and moisture content of the stack gas.

(i) Method 1 to select sampling port locations and the number of traverse points. Sampling ports must be located at the outlet of the control device and prior to any releases to the atmosphere.

(ii) Method 2, 2F, or 2G to determine the volumetric flow rate of the stack gas.

(iii) Method 3, 3A, or 3B to determine the dry molecular weight of the stack gas. The ANSI/ASME PTC 19–10–1981 Part 10 (incorporated by reference, see § 63.14) is an acceptable alternative to EPA Method 3B manual portion only but not the instrumental portion.

(iv) Method 4 to determine the moisture content of the stack gas.

(2) Determine the concentration of benzene and toluene for each stack using Method 18 in to appendix A–6 to 40 CFR part 60 to determine the concentration of benzene and toluene; or as an alternative ASTM D6420–99 (Reapproved 2010) (incorporated by reference, see § 63.14), may be used provided that the target compound(s) are those listed in section 1.1 of ASTM D6420–99 (Reapproved 2010) as measurable; the target compounds do not include methane and ethane because their atomic mass is less than 35; and the test results are not a total VOC method. Each test must consist of three separate runs. The duration of sampling must be at least two hours per run.

(3) Determine the concentration of chlorine and hydrogen chloride for each stack using Method 26A in appendix A–8 to 40 CFR part 60. Each test must consist of three separate runs. The minimum sample volume must be at least 2 dry cubic meters per run. Each run must be conducted for a minimum of 1 hour.

(4) Determine the concentration of polycyclic aromatic hydrocarbons excluding naphthalene, naphthalene, and dioxins/furans for each stack using Method 23 in appendix A–7 to 40 CFR part 60. Each test must consist of three separate runs. The test duration must be at least 3 hours and the must be at least 3 dscm (106 dscf). Method 23 complete list of PAHs and dioxin and furan congeners must be analyzed and reported.

(5) During each stack test run, measure the weight of copper concentrate feed charged to the smelting vessel and calculate the emissions rate in pounds of pollutant per ton of copper concentrate feed charged to the smelting vessel (lb/ton), except for dioxins/furans which should be calculated in nanograms of pollutant Toxicity Equivalent Quotient (TEQ) per megagram of copper concentrate feed charged to the smelting vessel (ng/Mg) for each test run. To calculate the TEQ, multiply each D/F congener emission concentration times the appropriate Toxicity Equivalent Factor (TEF) in table 3 to this subpart. If any measurement result is reported as below the method detection limit, use the method detection limit for that value when calculating the emission rate. Calculate the total emissions rate for each test run by summing the emissions across all stacks, as shown in equation 2 to this paragraph (f)(5).

Equation 2 to Paragraph (f)(5)

$$E_{f,i} = \sum_{s=1}^{n} \frac{C_s \times Q_s}{P}$$

Where:

$E_{f,i}$ = Emissions rate for test run ‘‘i’’ for all emission stacks at the facility ‘‘f’’, lb/ton or ng/Mg, as applicable of copper concentrate feed charged to the smelting vessel;

C_s = Emission rate for stack ‘‘s’’ measured during test run ‘‘i’’ on at facility ‘‘f’’, lb/dscf;

Q_s = Average volumetric flow rate of stack gas measured at stack ‘‘s’’ during test run ‘‘i’’ at facility ‘‘f’’, dscf/hour;

P = Copper concentrate feed charged to the smelting vessel during the stack test, ton/hour or Mg/hour, as applicable; and

n = Number of emissions stacks at facility ‘‘f’’.

(6) Calculate the average emissions rate for each facility using the three test runs, as shown in equation 3 to this paragraph (f)(6). For the purposes of determining compliance with the applicable emission limits in table 2 to this subpart, the arithmetic mean of the results for the three separate test runs is used as calculated using equation 3.

Equation 3 to paragraph (f)(6)

$$E_f = \frac{E_1 + E_2 + E_3}{3}$$

Where:

E_f = Average emission rate for facility ''f'', lb/ton or ng/Mg of copper concentrate feed charged to the smelting vessel, as applicable.

E_1 = Emissions rate for run 1 for facility ''f'', lb/ton or ng/Mg of copper concentrate feed charged to the smelting vessel, as applicable.

E_2 = Emissions rate for run 2 for facility ''f'', lb/ton or ng/Mg of copper concentrate feed charged to the smelting vessel, as applicable.

E_3 = Emissions rate for run 3 for facility ''f'', lb/ton or ng/Mg of copper concentrate feed charged to the smelting vessel, as applicable.

* * * * *

(7) For a control device applied to emissions from an affected source and subject to work practice standards and emission limit(s) in § 63.1444(o) for appropriate, site-specific operating parameters that are representative and reliable indicators of the control device performance, you must establish a site-specific operating limit(s) according to the procedures in paragraphs (f)(7)(i) through (iv) of this section.

(i) Select one or more operating parameters, as appropriate for the control device design, that can be used as representative and reliable indicators of the control device operation.

(ii) Using the CPMS required in § 63.1452, measure and record the selected operating parameters for the control device during each run of the benzene, toluene, chlorine, hydrogen chloride, polycyclic aromatic hydrocarbons excluding naphthalene, naphthalene and dioxins/furans performance test.

(iii) Compute and record the hourly average value for each of the selected operating parameters for each individual test run. Your operating limits are the lowest value or the highest value, as appropriate for the selected operating parameter, measured in any of the three runs that meet the applicable emission limit.

(iv) You must prepare written documentation to support your selection of the operating parameters used for the control device. This documentation must include a description of each selected parameter, a rationale for why you chose the parameter, a description of the method used to monitor the parameter, and the data recorded during the performance test and used to set the operating limit(s).

(8) You must conduct each performance test that applies to your affected source under normal operating conditions of the affected source. You may not conduct a performance test during a malfunction. The use of the bypass stack during a performance test of the process shall invalidate the performance test. 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 such conditions represent the entire range of normal operation, including operational conditions for maximum emissions if such emissions are not expected during maximum production. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(g) *Peirce-Smith converter department, Inco flash furnace, and anode refining department process fugitive roofline vent lead.* For facilities using a combination of Peirce-Smith converter department, Inco flash furnace, and anode refining department, you must conduct each performance test to determine compliance with the roofline vent process fugitive lead emission limits in § 63.1444(p)(1) that apply to you according to the requirements for representative test conditions specified in paragraph (g)(3) of this section and using the test methods and procedures in paragraphs (g)(1) and (2) of this section. You must also comply with establishing operating parameters in paragraphs (g)(4) through (7) of this section.

(1) Determine the concentration of Peirce-Smith converter department, Inco flash furnace, and anode refining department process fugitive roofline vent lead according to the test methods in appendices A–1 through A–8 to 40 CFR part 60 as specified in paragraphs (g)(1)(i) through (vii) of this section.

(i) Method 1 to select sampling port locations and the number of traverse points. Sampling ports must be located at the outlet of the control device and prior to any releases to the atmosphere. Use Method 5D section 8.1.3 Roof Monitor or Monovent or approved sample locations by MTG or delegated authority.

(ii) Method 2, 2F, or 2G to determine the volumetric flow rate of the stack gas or calibrated anemometer.

(iii) Method 3, 3A, or 3B to determine the dry molecular weight of the stack gas. The ANSI/ASME PTC 19–10–1981 Part 10 (incorporated by reference, see § 63.14) is an acceptable alternative to EPA Method 3B manual portion only but not the instrumental portion.

(iv) Method 4 to determine the moisture content of the stack gas.

(v) Method 17 to determine in-stack mass volume of the anode refining, converter and smelting process fugitive roof vent lead emissions. Isokinetic calculations are waived due to low flow rates and high variability. Use the filter specified in section 7.2.1 of Method 29. An approved FRM/FEM may be used if it can tolerate the 150 F temperatures on the roof vents. TEOMs are not appropriate for this sampling. An alternative test method may be requested to EPA OAR, OAQPS, Measurement Technology Group.

(vi) Method 29 filter analysis by inductively coupled plasma mass spectrometry (ICP–MS) for lead.

(vii) Method 9 to establish opacity as an operating parameter, if appropriate. ASTM D7520–16 (incorporated by reference, see § 63.14) is an acceptable alternative to EPA Method 9 with the specified conditions in paragraphs (c)(3)(i)(A) through (E) of this section.

(2) You must conduct three separate test runs for each performance test. Each test run must have a minimum sampling time of 12 hours. For the purpose of determining compliance with the lead emission limit, the arithmetic mean of the results for the three separate test runs for each roofline vent (*i.e.,* anode refining department, copper converter department, smelting vessels, slag cleaning vessels) is used. The three test run average of the lead emission rates from each vent should be summed to compare to the emission limit in § 63.1444.

(3) You must conduct each performance test that applies to your affected source under normal operating conditions of the affected source. The owner or operator may not conduct performance tests during periods of malfunction. The use of the bypass stack during a performance test of the process shall invalidate the performance test. 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 such conditions represent the entire range of normal operation, including operational conditions for maximum emissions if such emissions are not expected during maximum production. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(4) Establish a site-specific operating limit for a parameter, like opacity, based on values measured during the performance test.

(5) For your flash furnace capture system you must establish site specific operating parameters as specified in § 63.1444(p)(2)(i).

(6) For your fuming ladle capture system, you must establish site specific

operating parameters as specified in § 63.1444(p)(2)(ii).

(7) For your anode furnace secondary capture and control system, you must establish site specific operating parameters as specified in § 63.1444(p)(2)(iii).

§ 63.1451 How do I demonstrate initial compliance with the emission limitations, work practice standards, design standards, and operation and maintenance requirements that apply to me?

(a) *Filterable particulate matter emission limits.* For each copper concentrate dryer, smelting vessel, slag cleaning vessel, copper converter department, anode refining department, and combination of anode refining department and Hoboken converter process fugitive capture system subject to a filterable particulate matter emission limit in § 63.1444 or § 63.1446, you have demonstrated initial compliance if you meet both of the conditions in paragraphs (a)(1) and (2) of this section.

(1) The average concentration of filterable particulate matter from the affected source, any capture system, or control device applied to emissions from the affected source, measured according to the performance test procedures in § 63.1450(a), did not exceed the applicable emission limit, and establishes operating parameter.

(2) You have submitted a notification of compliance status according to the requirements in § 63.1454(e) and performance test results according to the requirements in § 63.1455(e).

(b) *Nonsulfuric acid particulate matter emissions limits.* For each smelting vessel, slag cleaning vessel, and copper converter departments subject to the nonsulfuric acid particulate matter emissions limit in § 63.1444 as applies to you, you have demonstrated initial compliance if you meet both of the conditions in paragraphs (b)(1) and (2) of this section.

(1) The average concentration of nonsulfuric acid particulate matter in the process off-gas discharged from the affected source, measured according to the performance test procedures in § 63.1450(b), did not exceed 6.2 mg/dscm.

(2) You have submitted a notification of compliance status according to the requirements in § 63.1454(e) and performance test results according to the requirements in § 63.1455(e).

(c) *Copper converter department visible emissions.* For each existing copper converter department subject to the opacity limit in § 63.1444, you have demonstrated initial compliance if you meet both of the conditions in paragraphs (c)(1) and (2) of this section.

(1) The opacity of visible emissions exiting the roof monitors or roof exhaust fans on the building housing the copper converter department measured according to the performance test procedures in § 63.1450(c), did not exceed 4 percent opacity.

(2) You have submitted a notification of compliance status according to the requirements in § 63.1454(e).

(d) *Copper converter department capture systems.* You have demonstrated initial compliance of the copper converter department capture system if you meet all of the conditions in paragraphs (d)(1) through (4) of this section.

(1) Prepared the capture system operation and maintenance plan according to the requirements in § 63.1447(b);

(2) Conducted an initial performance test according to the procedures of § 63.1450(c) demonstrating the opacity of any visible emissions exiting the roof monitors or roof exhaust fans on the building housing the copper converter department does not exceed 4 percent opacity;

(3) Included in your notification of compliance status a copy of your written capture system operation and maintenance plan and have certified in your notification of compliance status that you will operate the copper converter department capture system at all times during blowing at the values or settings established for the operating limits in that plan; and

(4) Submitted a notification of compliance status according to the requirements in § 63.1454(e) and performance test results according to the requirements in § 63.1455(e).

(e) *Baghouses.* For each baghouse subject to operating limits in § 63.1444(i) or § 63.1446(c), you have demonstrated initial compliance if you meet all of the conditions in paragraphs (e)(1) through (3) of this section.

(1) You have included in your written operation and maintenance plan required under § 63.1447(b) detailed descriptions of the procedures you use for inspection, maintenance, bag leak detection, and corrective action for the baghouse.

(2) You have certified in your notification of compliance status that you will operate the baghouse according to your written operation and maintenance plan.

(3) You have submitted the notification of compliance status according to the requirements in § 63.1454(e).

(f) *Venturi wet scrubbers.* For each venturi wet scrubber subject to operating limits in § 63.1444(j) or § 63.1446(d), you have demonstrated initial compliance if you meet all of the conditions in paragraphs (f)(1) through (3) of this section.

(1) Established site-specific operating limits for pressure drop and scrubber water flow rate and have a record of the pressure drop and scrubber water flow rate measured during the performance test you conduct to demonstrate initial compliance with paragraph (a) or (k) of this section.

(2) Certified in your notification of compliance status that you will operate the venturi wet scrubber within the established operating limits for pressure drop and scrubber water flow rate.

(3) Submitted a notification of compliance status according to the requirements in § 63.1454(e).

(g) *Other control devices.* For each control device other than a baghouse or venturi wet scrubber subject to operating limits in § 63.1444(k) or (n) or § 63.1446(e), you have demonstrated initial compliance if you meet all of the conditions in paragraphs (g)(1) through (4) of this section.

(1) Selected one or more operating parameters, as appropriate for the control device design, that can be used as representative and reliable indicators of the control device operation.

(2) Established site-specific operating limits for each of the selected operating parameters based on values measured during the performance test you conduct to demonstrate initial compliance with paragraph (a) of this section and have prepared written documentation according to the requirements in § 63.1450(a)(5)(iv).

(3) Included in your notification of compliance status a copy of the written documentation you have prepared to demonstrate compliance with paragraph (g)(2) of this section and have certified in your notification of compliance status that you will operate the control device within the established operating limits.

(4) Submitted a notification of compliance status according to the requirements in § 63.1454(e).

(h) *Fugitive dust sources.* For all fugitive dust sources subject to work practice standards in § 63.1445, you have demonstrated initial compliance if you meet all of the conditions in paragraphs (h)(1) through (3) of this section.

(1) Prepared a written fugitive dust control plan according to the requirements in § 63.1445 and it has been approved by the delegated authority.

(2) Certified in your notification of compliance status that you will control emissions from the fugitive dust sources

according to the procedures in the approved plan.

(3) Submitted the notification of compliance status according to the requirements in § 63.1454(e).

(i) *Operation and maintenance requirements.* You have demonstrated initial compliance with the operation and maintenance requirements that apply to you if you meet all of the conditions in paragraphs (i)(1) through (3) of this section.

(1) Prepared an operation and maintenance plan according to the requirements in § 63.1447(b).

(2) Certified in your notification of compliance status that you will operate each capture system and control device according to the procedures in the plan.

(3) Submitted the notification of compliance status according to the requirements in § 63.1454(e).

(j) *Mercury emissions.* For any combination of copper concentrate dryers, smelting vessel, copper converter department, slag cleaning vessel and anode refining department subject to a mercury emission limit in § 63.1444, you have demonstrated initial compliance if you meet the conditions in paragraphs (j)(1) through (3) of this section.

(1) The sum of the mercury emissions (lb/hr) from the affected sources measured according to the performance test procedures in § 63.1450(d), did not exceed the applicable emission limit.

(2) Established a site-specific operating limit for a parameter based on values measured during the performance test you conduct to demonstrate initial compliance with this paragraph (j) and have prepared written documentation according to the requirements in § 63.1450(d)(3)(iv).

(3) You have submitted a notification of compliance status according to the requirements in § 63.1454(e) and performance test results according to the requirements in § 63.1455(e).

(k) *Process fugitive filterable particulate matter from roofline vents.* For emissions from roofline vents associated with the smelting vessels, slag cleaning vessels, copper converter department, and anode refining department subject to a filterable particulate matter emission limit in § 63.1444(h), you have demonstrated initial compliance if you meet the conditions in paragraphs (k)(1) through (3) of this section.

(1) The sum of filterable particulate matter emissions from the combination of roofline vents as measured according to the performance test procedures in § 63.1450(e), did not exceed 6.3 lb/hr.

(2) Established a site-specific operating limit for a parameter, like opacity, based on values measured during the performance test you conduct to demonstrate initial compliance with this paragraph (k) and have prepared written documentation according to the requirements in § 63.1450(e).

(3) You have submitted a notification of compliance status according to the requirements in § 63.1454(e) and performance test results according to the requirements in § 63.1455(e).

(l) *Benzene, toluene, chlorine, hydrogen chloride, polycyclic aromatic hydrocarbons excluding naphthalene, naphthalene, and dioxins/furans emissions.* For any combination of copper concentrate dryer, smelting vessel, slag cleaning vessel, copper converter department, and anode refining department subject to the benzene, toluene, chlorine, hydrogen chloride, polycyclic aromatic hydrocarbons excluding naphthalene, naphthalene, and dioxins/furans emission limits in table 2 to this subpart, you have demonstrated initial compliance if you meet both of the conditions in paragraphs (l)(1) and (2) to this section.

(1) The emissions of benzene, toluene, chlorine, hydrogen chloride, polycyclic aromatic hydrocarbons excluding naphthalene, naphthalene, and dioxins/furans emissions per mass of copper concentrate feed to the smelting vessel from the affected sources measured according to the performance test procedures in § 63.1450(f), did not exceed the applicable emission limit.

(2) You have submitted a notification of compliance status according to the requirements in § 63.1454(e) and performance test results according to the requirements in § 63.1455(e).

(m) *Process fugitive lead from roofline vents.* For emissions from the combination of roofline vents associated with the Peirce-Smith converter department, Inco flash furnace, and anode refining department subject to a lead emission limit and design standards in § 63.1444(p), you have demonstrated initial compliance if you meet the conditions in paragraphs (m)(1) through (5) of this section.

(1) The sum of lead emissions from the combination of roofline vents as measured according to the performance test procedures in § 63.1450(g), did not exceed 0.326 lb/hr.

(2) You have submitted a notification of compliance status and performance test results according to requirements of §§ 63.1454(e), 63.1455(e)(1), and 63.9(k)

(3) For your flash furnace capture system, you have established timed interlock on the slag return launder.

(4) For your fuming ladle capture system, you have determined flow rate by a calibrated flowmeter or test.

(5) For your anode furnace secondary hood capture and control system, you have determined flow rate by a calibrated flowmeter or test.

§ 63.1452 What are my monitoring requirements?

(a) *Copper converter department capture systems.* For each operating limit established under your capture system operation and maintenance plan, you must install, operate, and maintain an appropriate monitoring device according to the requirements in paragraphs (a)(1) through (6) of this section to measure and record the operating limit value or setting at all times the copper converter department capture system is operating during batch copper converter blowing. Dampers that are manually set and remain in the same position at all times the capture system is operating are exempted from the requirements of this paragraph (a).

(1) Install the monitoring device, associated sensor(s), and recording equipment according to the manufacturers' specifications. Locate the sensor(s) used for monitoring in or as close to a position that provides a representative measurement of the parameter being monitored.

(2) If a flow measurement device is used to monitor the operating limit parameter, you must meet the requirements in paragraphs (a)(2)(i) through (iv) of this section.

(i) Locate the flow sensor and other necessary equipment such as straightening vanes in a position that provides a representative flow.

(ii) Use a flow sensor with a minimum tolerance of 2 percent of the flow rate.

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

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

(3) If a pressure measurement device is used to monitor the operating limit parameter, you must meet the requirements in paragraphs (a)(3)(i) through (v) of this section.

(i) Locate the pressure sensor(s) in or as close to a position that provides a representative measurement of the pressure.

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

(iii) Use a gauge with a minimum tolerance of 0.5 inch of water or a transducer with a minimum tolerance of 1 percent of the pressure range.

(iv) Check pressure tap pluggage daily.

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

(4) Conduct calibration and validation checks any time the sensor exceeds the manufacturer's specifications or you install a new sensor.

(5) At least monthly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage.

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

(b) *Baghouses.* For each baghouse subject to the operating limit in § 63.1444(i) or § 63.1446(c) for the bag leak detection system alarm, you must at all times monitor the relative change in particulate matter loadings using a bag leak detection system according to the requirements in paragraph (b)(1) of this section and conduct regular inspections according to the requirements in paragraph (b)(2) of this section.

(1) You must install, operate, and maintain each bag leak detection system according to the requirements in paragraphs (b)(1)(i) through (vii) of this section.

(i) The system must be certified by the manufacturer to be capable of detecting emissions of particulate matter at concentrations of 10 milligrams per actual cubic meter (0.0044 grains per actual cubic foot) or less.

(ii) The system must provide output of relative changes in particulate matter loadings.

(iii) The system must be equipped with an alarm that will sound when an increase in relative particulate loadings is detected over a preset level. The alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) Each system that works based on the triboelectric effect must be installed, operated, and maintained in a manner consistent with the guidance document ''Fabric Filter Bag Leak Detection Guidance,'' EPA–454/R–98–015, September 1997. You may obtain a copy of this guidance document by contacting the National Technical Information Service (NTIS) at 800–553–6847. You may install, operate, and maintain other types of bag leak detection systems in a manner consistent with the manufacturer's written specifications and recommendations.

(v) To make the initial adjustment of the system, establish the baseline output by adjusting the sensitivity (range) and the averaging period of the device. Then, establish the alarm set points and the alarm delay time.

(vi) Following the initial adjustment, do not adjust the sensitivity or range, averaging period, alarm set points, or alarm delay time, except as detailed in your operation and maintenance plan. Do not increase the sensitivity by more than 100 percent or decrease the sensitivity by more than 50 percent over a 365-day period unless a responsible official certifies, in writing, that the baghouse has been inspected and found to be in good operating condition.

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

(2) You must conduct baghouse inspections at their specified frequencies according to the requirements in paragraphs (b)(2)(i) through (viii) of this section.

(i) Monitor the pressure drop across each baghouse cell each day to ensure pressure drop is within the normal operating range identified in the manual.

(ii) Confirm that dust is being removed from hoppers through weekly visual inspections or other means of ensuring the proper functioning of removal mechanisms.

(iii) Check the compressed air supply for pulse-jet baghouses each day.

(iv) Monitor cleaning cycles to ensure proper operation using an appropriate methodology.

(v) Check bag cleaning mechanisms for proper functioning through monthly visual inspection or equivalent means.

(vi) Make monthly visual checks of bag tension on reverse air and shaker-type baghouses to ensure that bags are not kinked (kneed or bent) or laying on their sides. You do not have to make this check for shaker-type baghouses using self-tensioning (spring-loaded) devices.

(vii) Confirm the physical integrity of the baghouse through quarterly visual inspections of the baghouse interior for air leaks.

(viii) Inspect fans for wear, material buildup, and corrosion through quarterly visual inspections, vibration detectors, or equivalent means.

(c) *Venturi wet scrubbers.* For each venturi wet scrubber subject to the operating limits for pressure drop and scrubber water flow rate in § 63.1444(j) or § 63.1446(d), you must at all times monitor the hourly average pressure drop and water flow rate using a CPMS. You must install, operate, and maintain each CPMS according to the requirements in paragraphs (c)(1) and (2) of this section.

(1) For the pressure drop CPMS, you must meet the requirements in paragraphs (c)(1)(i) through (vi) of this section.

(i) Locate the pressure sensor(s) in or as close to a position that provides a representative measurement of the pressure and that minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.

(ii) Use a gauge with a minimum measurement sensitivity of 0.5 inch of water or a transducer with a minimum measurement sensitivity of 1 percent of the pressure range.

(iii) Check the pressure tap for pluggage daily.

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

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

(vi) At least monthly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage.

(2) For the scrubber water flow rate CPMS, you must meet the requirements in paragraphs (c)(2)(i) through (iv) of this section.

(i) Locate the flow sensor and other necessary equipment in a position that provides a representative flow and that reduces swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

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

(iii) Conduct a flow sensor calibration check at least semiannually according to the manufacturer's instructions.

(iv) At least monthly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage.

(d) *Other control devices and operating parameters.* For each control device other than a baghouse or venturi wet scrubber subject to the operating limits for appropriate parameters in § 63.1444(k) or § 63.1446(e), or a control device for mercury subject to § 63.1444(n), you must at all times monitor each of your selected parameters using an appropriate CPMS. You must install, operate, and maintain each CPMS according to the equipment manufacturer's specifications and the requirements in paragraphs (d)(1) though (5) of this section.

(1) Locate the sensor(s) used for monitoring in or as close to a position that provides a representative measurement of the parameter being monitored.

(2) Determine the hourly average of all recorded readings.

(3) Conduct calibration and validation checks any time the sensor exceeds the manufacturer's specifications or you install a new sensor.

(4) At least monthly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage.

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

(e) *Continuous monitoring.* Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times an affected source is operating.

(f) *Data collection for assessing compliance.* 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 or to fulfill a minimum data availability requirement, if applicable. You must use all the data collected during all other periods in assessing compliance.

(g) *Monitoring malfunctions.* A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitor to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(h) *Bypass stacks.* You must maintain an appropriate monitoring device according to the requirements in paragraph (h)(1) or (2) of this section to demonstrate the work practice standards are limiting the emissions at all times the bypass stack is in use.

(1) If a SO_2 continuous emissions monitoring system (CEMS) is utilized as a continuous monitor during planned maintenance events, a cylinder gas audit (CGA) and daily calibration or a 3-point linearity test must be conducted prior to the performance test according to Procedure 1, section 5.1.2, in appendix F to 40 CFR part 60 to conduct the CGA.

(2) If a particulate matter (PM) detector is CPMS, you must install, operate, and maintain each PM detector according to the equipment manufacturer's specifications and the requirements in paragraphs (h)(2)(i) through (v) of this section.

(i) Locate the detector(s) used for monitoring in or as close to a position that provides a representative measurement of the parameter being monitored.

(ii) Determine the hourly average of all recorded readings.

(iii) Conduct calibration and validation checks any time the detector exceeds the manufacturer's specifications or you install a new detector.

(iv) At least monthly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage.

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

§ 63.1453 How do I demonstrate continuous compliance with the emission limitations, work practice standards, design standards, and operation and maintenance requirements that apply to me?

(a) *Filterable particulate matter emission limits.* For each affected source subject to a particulate matter emission limit in § 63.1444 or § 63.1446 as applies to you, you must demonstrate continuous compliance according to the requirements in paragraphs (a)(1) and (2) of this section.

(1) For each copper concentrate dryer, smelting vessel, slag cleaning vessel, copper converter department, anode refining department, and combination of anode refining department and Hoboken converter process fugitive capture system subject to a filterable particulate matter emission limit in § 63.1444 or § 63.1446 as applies to you, you must demonstrate continuous compliance by meeting the conditions in paragraphs (a)(1)(i) through (iii) or paragraphs (a)(1)(i) and (iv) through (vii) of this section.

(i) Maintain the average concentration of filterable particulate matter in the gases discharged from the affected source at or below the applicable emission limit. If a particulate matter continuous emissions monitoring system (PM CEMS) is used, you must demonstrate continued compliance according to the requirements in paragraphs (a)(1)(iv) through (vii) of this section.

(ii) Monitor the operating parameter(s) established during the performance test according to the requirements in §§ 63.1450(a) and 63.1452 and collect, reduce, and record the monitoring data for each of the operating limit parameters according to the applicable requirements of this subpart.

(iii) Conduct subsequent performance tests following your initial performance test no less frequently than once per year according to the performance test procedures in § 63.1450(a). New operating limits may be established during subsequent performance tests as long as the performance tests demonstrate compliance with the emission limits.

(iv) Install, operate, and maintain a PM CEMS to measure and record PM concentrations and gas stream flow rates for the exhaust gases discharged to the atmosphere from each affected source subject to the emissions limit in this paragraph (a)(1). A single PM CEMS may be used for the combined exhaust gas streams from multiple affected sources at a point before the gases are discharged to the atmosphere. For each PM CEMS used to comply with this paragraph (a)(1), you must meet the requirements in this paragraph (a)(1)(iv) and paragraphs (a)(1)(v) through (vii) of this section.

(v) You must install, certify, operate, and maintain the PM CEMS according to EPA Performance Specification 11 in appendix B to 40 CFR part 60, and the quality assurance requirements of Procedure 2 in appendix F to 40 CFR part 60.

(vi) You must conduct an initial performance evaluation of the PM CEMS according to the requirements of Performance Specification 11 in appendix B to 40 CFR part 60. Thereafter, you must perform the performance evaluations as required by Procedure 2 in appendix F to 40 CFR part 60.

(vii) You must perform quarterly accuracy determinations and daily calibration drift tests for the PM CEMS according to Procedure 2 in appendix F to 40 CFR part 60.

(2) For each smelting vessel, slag cleaning vessel, and copper converter department subject to the nonsulfuric acid particulate matter emission limit in § 63.1444 as applies to you, you must demonstrate continuous compliance by meeting the conditions in paragraphs (a)(2)(i) through (iii) of this section.

(i) Maintain the average concentration of nonsulfuric acid particulate matter in the process off-gas discharged from the affected source at or below 6.2 mg/dscm.

(ii) Monitor the operating parameter established during the performance tests according to the requirements in §§ 63.1450(b) and 63.1452 and collect, reduce, and record the monitoring data for each of the operating limit parameters according to the applicable requirements of this subpart.

(iii) Conduct subsequent performance tests following your initial performance test no less frequently than once per year according to the performance test procedures in § 63.1450(b). New operating limits may be established during subsequent performance tests as long as the performance tests demonstrate compliance with the emission limits.

(b) *Copper converter department capture systems.* You must demonstrate continuous compliance of the copper converter department capture system by meeting the requirements in paragraphs (b)(1) through (4) of this section.

(1) Operate the copper converter department capture system at all times during blowing at or above the lowest values or settings established for the operating limits and demonstrated to achieve the opacity limit according to the applicable requirements of this subpart;

(2) Inspect and maintain the copper converter department capture system according to the applicable requirements in § 63.1447 and recording all information needed to document conformance with these requirements;

(3) Monitor the copper converter department capture system according to the requirements in § 63.1452(a) and collecting, reducing, and recording the monitoring data for each of the operating limit parameters according to the applicable requirements of this subpart; and

(4) Conduct subsequent performance tests according to the requirements of § 63.1450(c) following your initial performance test no less frequently than once per year to demonstrate that the opacity of any visible emissions exiting the roof monitors or roof exhaust fans on the building housing the copper converter department does not exceed 4 percent opacity.

(c) *Baghouses.* For each baghouse subject to the operating limit for the bag leak detection system alarm in § 63.1444(i) or § 63.1446(c), you must demonstrate continuous compliance by meeting the requirements in paragraphs (c)(1) through (3) of this section.

(1) Maintain the baghouse such that the bag leak detection system alarm does not sound for more than 5 percent of the operating time during any semiannual reporting period. To determine the percent of time the alarm sounded use the procedures in paragraphs (c)(1)(i) through (v) of this section.

(i) Alarms that occur due solely to a malfunction of the bag leak detection system are not included in the calculation.

(ii) Before November 12, 2024, alarms that occur during startup, shutdown, or malfunction are not included in the calculation if the condition is described in the startup, shutdown, and malfunction plan, and you operated the source during such periods in accordance with § 63.6(e)(1). On or after November 12, 2024, alarms that occur due solely to a malfunction of the bag leak detection system are not included in the calculation.

(iii) Count 1 hour of alarm time for each alarm when you initiated procedures to determine the cause of the alarm within 1 hour.

(iv) Count the actual amount of time you took to initiate procedures to determine the cause of the alarm if you did not initiate procedures to determine the cause of the alarm within 1 hour of the alarm.

(v) Calculate the percentage of time the alarm on the bag leak detection system sounds as the ratio of the sum of alarm times to the total operating time multiplied by 100.

(2) Maintain records of the times the bag leak detection system alarm sounded, and for each valid alarm, the time you initiated corrective action, the corrective action(s) taken, and the date on which corrective action was completed.

(3) Inspect and maintain each baghouse according to the requirements in § 63.1452(b)(2) and recording all information needed to document conformance with these requirements. If you increase or decrease the sensitivity of the bag leak detection system beyond the limits specified in § 63.1452(b)(1)(vi), you must include a copy of the required written certification by a responsible official in the next semiannual compliance report.

(d) *Venturi wet scrubbers.* For each venturi wet scrubber subject to the operating limits for pressure drop and scrubber water flow rate in § 63.1444(j) or § 63.1446(d), you must demonstrate continuous compliance by meeting the requirements of paragraphs (d)(1) through (3) of this section.

(1) Maintain the hourly average pressure drop and scrubber water flow rate at levels no lower than those established during the initial or subsequent performance test;

(2) Inspect and maintain each venturi wet scrubber CPMS according to § 63.1452(c) and recording all information needed to document conformance with these requirements; and

(3) Collect and reduce monitoring data for pressure drop and scrubber water flow rate according to § 63.1452(e) and recording all information needed to document conformance with these requirements.

(e) *Other control devices.* For each control device other than a baghouse or venturi wet scrubber subject to the operating limits for site-specific operating parameters in § 63.1444(k) or § 63.1446(e), you must demonstrate continuous compliance by meeting the requirements of paragraphs (e)(1) through (3) of this section:

(1) Maintain the hourly average rate at levels no lower than those established during the initial or subsequent performance test;

(2) Inspect and maintain each CPMS operated according to § 63.1452(d) and record all information needed to document conformance with these requirements; and

(3) Collect and reduce monitoring data for selected parameters according to § 63.1452(e) and recording all information needed to document conformance with these requirements.

(f) *Fugitive dust sources.* For each fugitive dust source subject to work practice standards in § 63.1445, you must demonstrate continuous compliance by implementing all of fugitive control measures specified for the source in your written fugitive dust control plan.

(g) *Mercury emissions.* For each affected source subject to mercury emissions limit in § 63.1444 as applies to you must demonstrate continuous compliance according to the requirements in paragraph (g)(1) or paragraphs (g)(2) and (3) of this section.

(1) Maintain the average concentration of mercury discharged from the facility at or below the emission limit in § 63.1444 monitored by a mercury continuous emissions monitoring system (Hg CEMS). If the Hg CEMS is used, you must demonstrate continuous compliance according to the requirements in paragraphs (g)(1)(i) through (v) of this section.

(i) Install and operate a Hg CEMS in accordance with Performance Specification 12A (PS 12A) of appendix B to 40 CFR part 60.

(ii) Maintain each Hg CEMS according to the quality assurance requirements in Procedure 5 of appendix F to 40 CFR part 60. The relative accuracy testing of Hg CEMS must be conducted at normal operating conditions.

(iii) Use a span value for any Hg CEMS that represents the mercury concentration corresponding to approximately two times the emissions standard and may be rounded up to the nearest multiple of 5 μg/m3 of total mercury or higher level if necessary to include Hg concentrations which may occur.

(iv) Determine the average on a 6-hour rolling basis.

(v) Install, operate, calibrate, and maintain an instrument for continuously measuring and recording the exhaust gas flow rate to the atmosphere.

(2) Monitor the operating parameter established during the performance tests

according to the requirements in §§ 63.1450(d) and 63.1452 and collecting, reducing, and recording the monitoring data for each of the operating limit parameters according to the applicable requirements of this subpart.

(3) Conduct subsequent performance tests following your initial performance test no less frequently than once per year according to the performance test procedures in § 63.1450(d). New operating limits may be established during subsequent performance tests as long as the performance tests demonstrate compliance with the emission limits.

(h) *Process fugitive filterable particulate matter and lead from roofline vents.* For emissions from roofline vents associated with the smelting vessels, slag cleaning vessels, copper converter department, and anode refining department subject to a filterable particulate matter emission limit in § 63.1444(h), and for emissions from the combination of roofline vents associated with the Peirce-Smith converter department, Inco flash furnace, and anode refining department subject to a lead emission limit in § 63.1444(p), you must demonstrate continuous compliance according to the requirements in paragraph (h)(1) or (2) and paragraph (h)(3) of this section. For the applicable design standards in § 63.1444(p), you must demonstrate continuous compliance according to the requirements in paragraphs (h)(4) through (6) of this section.

(1) *Operating parameter.* You must demonstrate continuous compliance with the established site-specific operating limit for a parameter, like opacity, based on values measured during the performance test you conduct to demonstrate initial compliance. If the operating parameter is visible emissions (VE) at each roofline vent, you must meet the requirements in paragraphs (h)(1)(i) through (v) of this section.

(i) Perform daily VE observations of each roofline vent according to the procedures of Method 22 of appendix A–7 to 40 CFR part 60. You must conduct the Method 22 test while the affected source is operating under normal conditions. The duration of each Method 22 test must be at least 15 minutes.

(ii) If VE are observed during any daily test conducted using Method 22 of appendix A–7 to 40 CFR part 60, you must promptly conduct an opacity test, according to the procedures of Method 9 of appendix A–4 to 40 CFR part 60. ASTM D7520–16 (incorporated by reference, see § 63.14) is an acceptable alternative to EPA Method 9 with the specified conditions in § 63.1450(c)(3)(i)(A) through (E).

(iii) You may decrease the frequency of Method 22 testing from daily to weekly for a roofline vent if one of the conditions in paragraph (h)(1)(iii)(A) or (B) of this section is met.

(A) No VE are observed in 30 consecutive daily Method 22 tests for any roofline vent; or

(B) No opacity greater than the site-specific operating limit is observed during any of the tests under Method 9 of appendix A–4 to 40 CFR part 60 for any roofline vent.

(iv) If VE are observed during any weekly test and opacity greater than the site-specific operating limit is observed in the subsequent test under Method 9 of appendix A–4 to 40 CFR part 60, you must promptly initiate and complete corrective actions according to your operation, maintenance, and monitoring plan (OM&M) plan, resume testing of that roof vent following Method 22 of appendix A–7 to 40 CFR part 60, on a daily basis, as described in paragraph (h)(1)(i) of this section, and maintain that schedule until one of the conditions in paragraph (h)(1)(iii)(A) or (B) of this section is met, at which time you may again decrease the frequency of Method 22 testing to a weekly basis.

(v) If greater than the site-specific opacity operating limit is observed during any test conducted using Method 9 of appendix A–4 to 40 CFR part 60, you must report these deviations by following the requirements in § 63.1455.

(2) Monitor the site-specific operating parameter established during the performance tests according to the requirements in § 63.1450(e) for filterable particulate matter and § 63.1450(g) for lead if applicable, and § 63.1452, collect, reduce, and record the monitoring data for each of the operating limit parameters according to the applicable requirements of this subpart.

(3) Conduct subsequent performance tests following your initial performance test no less frequently than once per year according to the performance test procedures in § 63.1450(e) for filterable particulate matter and § 63.1450(g) for lead if applicable. New operating limits may be established during subsequent performance tests as long as the performance tests demonstrate compliance with the emission limits.

(4) For your flash furnace capture system, you must inspect the hooding, walls, and damper quarterly.

(5) For your fuming ladle capture system, you must inspect the hooding, walls, and ladle during maintenance periods.

(6) For your anode furnace secondary hood capture and control system, you must inspect the hood, walls, and damper during maintenance periods, and operate anode furnace secondary hood system at all times the anode furnaces are operating.

(i) *Benzene, toluene, chlorine, hydrogen chloride, polycyclic aromatic hydrocarbons excluding naphthalene, naphthalene, and dioxins/furans emissions.* For each affected source subject to the benzene, toluene, chlorine, hydrogen chloride, polycyclic aromatic hydrocarbons excluding naphthalene, naphthalene, and dioxins/furans emission limits in table 2 to this subpart, you must demonstrate continuous compliance according to paragraphs (i)(1) and (2) to this section.

(1) You must monitor the site-specific operating parameter established during the performance tests according to the requirements in § 63.1450(f) and collect, reduce, and record the monitoring data for each of the operating limit parameters according to the applicable requirements of this subpart.

(2) You must demonstrate continuous compliance by conducting subsequent performance tests following your initial performance test at least once every five years according to the performance test procedures in § 63.1450(f). New operating limits may be established during subsequent performance tests as long as the performance tests demonstrate compliance with the emission limits.

§ 63.1454 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.6(h)(4) and (5), 63.7(b) and (c), 63.8(f)(4), and 63.9(b) through (h) that apply to you by the specified dates.

(b) As specified in § 63.9(b)(2), if you start your affected source before June 12, 2002, you must submit your initial notification not later than October 10, 2002, or no later than 120 days after the source becomes subject to this subpart (see § 63.1441), whichever is later.

(c) As specified in § 63.9(b)(3), if you start your new affected source on or after June 12, 2002, you must submit your initial notification not later than 120 calendar days after you become subject to this subpart (see § 63.1441).

(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 calendar days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(e) If you are required to conduct a performance test, opacity observation, or other initial compliance demonstration, you must submit a notification of compliance status according to § 63.9(h)(2)(ii) by the date specified in paragraph (e)(1) or (2) of this section as applies to you.

(1) For each initial compliance demonstration that does not include a performance test, you must submit the notification of compliance status before the close of business on the 30th calendar day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration that includes a performance test, you must submit the notification of compliance status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test according to § 63.10(d)(2).

§ 63.1455 What reports must I submit and when?

(a) You must submit each report in paragraphs (a)(1) and (2) of this section that applies to you.

(1) You must submit a compliance report semiannually according to the requirements in paragraph (b) of this section and containing the information in paragraph (c) of this section.

(2) Before November 12, 2024, you must submit an immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan. You must report the actions taken for the event by fax or telephone within 2 working days after starting actions inconsistent with the plan. You must submit the information in § 63.10(d)(5)(ii) by letter within 7 working days after the end of the event unless you have made alternative arrangements with the delegated authority. On or after November 12, 2024, you must report any deviation from an applicable standard in §§ 63.1444, 63.1445, and 63.1446 as part of your semiannual compliance report and include the information required in paragraph (c) of this section. In an event of an emergency situation, you must report the emergency and the actions taken for the event by email or telephone within 2 working days of the time when emissions limitations were exceeded due to the emergency (or an alternate timeframe acceptable to the delegated authority). For the purposes of complying with this paragraph (a)(2), an emergency situation is any situation arising from sudden and reasonably unforeseeable events beyond the control of the facility owner or operator that requires immediate corrective action to restore normal operation, and that causes the affected source to exceed an applicable emissions limitation under this subpart, due to unavoidable increases in emissions attributable to the emergency. An emergency must not include noncompliance to the extent it is caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. You must submit the report within 7 working days after the end of the event unless you have made alternative arrangements with the delegated authority. This report must contain a description of the emergency, any steps take to mitigate the emissions and corrective actions taken.

(b) Unless the Administrator has approved a different schedule under § 63.10(a), you must submit each compliance report required in paragraph (a) of this section according to the applicable requirements in paragraphs (b)(1) through (5) of this section following the procedures in § 63.9(k).

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.1443 and ending on June 30 or December 31, whichever date comes first after the compliance date that is specified for your source in § 63.1443.

(2) The first compliance report must be delivered no later than July 31 or January 31, whichever date comes first after your first compliance report is due.

(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 delivered no later than July 31 or January 31, whichever date comes first after the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the delegated authority has established dates for submitting semiannual reports pursuant to 40 CFR 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 delegated authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) Each compliance report must contain the information in paragraphs (c)(1) through (3) of this section and, as applicable, paragraphs (c)(4) through (8) of this section.

(1) Company name and address.

(2) Statement by a responsible official, as defined in § 63.2, with that official's name, title, and signature, certifying the accuracy and completeness of the content of the report.

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

(4) Before November 12, 2024, if you had a startup, shutdown or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in § 63.10(d)(5)(i). On or after November 12, 2024, you are not required to have a startup, shutdown, and malfunction plan and you are not required to include in your report the information in § 63.10(d)(5)(i).

(5) If there are no deviations from any emission limitations (emission limit, operating limit, opacity limit) that applies to you and there are no deviations from the requirements for work practice standards in this subpart, a statement that there were no deviations from the emission limitations, work practice standards, or operation and maintenance requirements during the reporting period.

(6) If there were no periods during which an operating parameter monitoring system was out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the monitoring system was out-of-control during the reporting period.

(7) For each deviation from an emission limitation (emission limit, operating limit, opacity limit) and for each deviation from the requirements for work practice standards that occurs at an affected source where you are not using a continuous monitoring system to comply with the emission limitations or work practice standards in this subpart, the compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (c)(7)(i) and (ii) of this section.

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

(ii) Information on the number, date, time, duration, and cause of deviations (including unknown cause, if applicable), as applicable, the corrective action taken, a list of the affected sources or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit, and a description of the method used to estimate the emissions.

(8) For each deviation from an emission limitation (emission limit,

operating limit, opacity limit, and visible emission limit) occurring at an affected source where you are using an operating parameter monitoring system to comply with the emission limitation in this subpart, you must include the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (c)(8)(i) through (xi) of this section.

(i) The cause of each deviations (including unknown cause, if applicable), the corrective action taken, a list of the affected sources or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit, and a description of the method used to estimate the emissions.

(ii) If the monitoring system was inoperative, the date and time that each monitoring system was inoperative, except for zero (low-level) and high-level checks.

(iii) If the monitoring system was inoperative, the date, time and duration that each monitoring system was out-of-control, including the information in § 63.8(c)(8).

(iv) The number, date and time that each deviation started and stopped.

(v) 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.

(vi) 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.

(vii) A summary of the total duration of monitoring system downtime during the reporting period and the total duration of monitoring system downtime as a percent of the total source operating time during that reporting period.

(viii) A brief description of the process units.

(ix) A brief description of the monitoring system.

(x) The date of the latest monitoring system certification or audit.

(xi) A description of any changes in continuous monitoring systems, processes, or controls since the last reporting period.

(d) If you have 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 71.6(a)(3)(iii)(A). If you submit a compliance report pursuant to paragraph (a) of this section along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limitation (including any operating limit), or work practice requirement in this subpart, submission of the compliance report is deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation you may have to report deviations from permit requirements to the permit authority.

(e) Within 60 days after the date of completing each performance test or continuous monitoring system (CMS) performance evaluation (as defined in § 63.2) required by this subpart, the owner or operator must submit the results of the performance test or performance evaluation following the procedures specified in § 63.9(k).

(1) *Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.* Submit the results of the performance test or the performance evaluation of CMS measuring relative accuracy test audit (RATA) pollutants to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The data must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(2) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test or the performance evaluation of CMS measuring RATA pollutants by methods that are not supported by the ERT, must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

§ 63.1456 What records must I keep and how long must I keep my records?

(a) You must keep the records listed in paragraphs (a)(1) through (8) 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) Before November 12, 2024, the records in § 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction. On or after November 12, 2024, you are not required to keep the records required in § 63.6(e)(3)(iii) through (v) related to compliance with a startup, shutdown, and malfunction plan.

(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(4) For each monitoring system, you must keep the records specified in paragraphs (a)(4)(i) through (iv) of this section.

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

(ii) Monitoring data recorded by the monitoring system during a performance evaluation as required in § 63.6(h)(7)(i) and (ii).

(iii) Before November 12, 2024, previous (i.e., superseded) versions of the performance evaluation plan as required in § 63.8(d)(3). On or after November 12, 2024, you must comply with the requirements in § 63.8(d)(1) and (2). The owner or operator shall keep the written procedures required in § 63.8(d)(1) and (2) on record 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, the owner or operator shall 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).

(iv) Before November 12, 2024, records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. On or after November 12, 2024, for each failure to meet an applicable standard, you must record the information in paragraphs (a)(4)(iv)(A) through (D) of this section. Examples of such methods to estimate emissions include product-loss calculations, mass balance calculations, measurements, or engineering judgment based on known process parameters.

(A) The occurrence and duration of each startup, shutdown, or malfunction of process, air pollution control, and monitoring equipment.

(B) 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, cause and duration of each failure.

(C) For each failure to meet an applicable standard, record and retain a list of the affected sources or equipment, whether the failure occurred during a period of startup, shutdown or malfunction, actions taken to minimize emissions, an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions.

(D) Record actions taken to minimize emissions in accordance with § 63.1447(a), and any corrective actions taken to return the affected unit to its normal or usual manner of operation.

(5) For each performance test you conduct to demonstrate compliance with an opacity limit according to § 63.1450(c), you must keep the records specified in paragraphs (a)(5)(i) through (ix) of this section.

(i) Dates and time intervals of all opacity observation period segments;

(ii) Description of overall smelter operating conditions during each observation period. Identify, if any, the smelter copper production process equipment that was out-of-service during the performance test and explain why this equipment was not in operation;

(iii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test;

(iv) Name, title, and affiliation for each indoor process monitor participating in the performance test;

(v) Copies of all visible emission observer opacity field data sheets;

(vi) Copies of all indoor process monitor operating log sheets;

(vii) Copies of all data summary sheets used for data reduction;

(viii) Copy of calculation sheets of the average opacity value used to demonstrate compliance with the opacity limit; and

(ix) Documentation according to the requirements in § 63.1450(c)(9)(iv) to support your selection of the site-specific capture system operating limits used for each batch copper converter capture system when blowing.

(6) For each baghouse subject to the operating limit in § 63.1444(i) or § 63.1446(c), you must keep the records specified in paragraphs (a)(6)(i) and (ii) of this section.

(i) Records of alarms for each bag leak detection system.

(ii) Description of the corrective actions taken following each bag leak detection alarm.

(7) For each control device other than a baghouse or venturi wet scrubber subject to site-specific operating limits in § 63.1444(k) or § 63.1446(e), you must keep documentation according to the requirements in § 63.1450(a)(5)(iv) to support your selection of the site-specific operating limits for the control device.

(8) You must keep records of bypass stack usage, including the flow rate and operating parameter(s).

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

(c) 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.

(d) 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 off site for the remaining 3 years.

§ 63.1457 What part of the general provisions apply to me?

Table 1 to this subpart shows which parts of the general provisions in §§ 63.1 through 63.15 apply to you.

§ 63.1458 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by us, the United States Environmental Protection Agency (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 subpart E of this part, the authorities listed in paragraph (c) of this section are retained by the U.S. EPA Administrator 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 as listed in paragraphs (c)(1) through (5) of this section.

(1) Approval of alternatives to the emission limitations and work practice standards in §§ 63.1444 through 63.1446 under § 63.6(g).

(2) Approval of major alternatives to test methods under § 63.7(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 an alternative to any electronic reporting to the EPA required by this subpart.

§ 63.1459 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2, and in this section as follows:

Anode refining department means the area at a primary copper smelter in which anode copper refining operations are performed. Emission sources in the anode refining department include anode refining furnaces and utility vessels.

Baghouse means a control device that collects particulate matter by filtering the gas stream through bags. A baghouse is also referred to as a ‘‘fabric filter.’’

Bag leak detection system means a system that is capable of continuously monitoring relative particulate matter (dust) loadings in the exhaust of a baghouse in order 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, transmittance or other effect to continuously monitor relative particulate matter loadings.

Batch copper converter means a Peirce-Smith converter or Hoboken converter in which copper matte is oxidized to form blister copper by a process that is performed in discrete batches using a sequence of charging, blowing, skimming, and pouring.

Blowing means the operating mode for a batch copper converter during which air or oxygen-enriched air is injected into the molten converter bath.

Bypass stack means a device used for discharging combustion gases to avoid severe damage to the air pollution control device or other equipment and conduct planned maintenance safely in accordance with the work practice standard in § 63.1444(q). The use of a bypass stack during a performance test of a process or control device will invalidate the test.

Capture system means the collection of components used to capture gases and fumes released from one or more emission points, and to convey the captured gases and fumes to a control device. A capture system may include, but is not limited to, the following components as applicable to a given capture system design: duct intake devices, hoods, enclosures, ductwork, dampers, manifolds, plenums, and fans.

Charging means the operating mode for a batch copper converter during which molten or solid material is added into the vessel.

Control device means the air pollution control equipment used to collect particulate matter and other emissions from a gas stream.

Converting vessel means a furnace, reactor, or other type of vessel in which copper matte is oxidized to form blister copper.

Copper concentrate dryer means a vessel in which copper concentrates are heated in the presence of air to reduce the moisture content of the material. Supplemental copper-bearing feed materials and fluxes may be added or mixed with the copper concentrates fed to a copper concentrate dryer.

Copper concentrate feed means the mixture of copper concentrate, secondary copper-bearing materials, recycled slags and dusts, fluxes, and other materials blended together for feeding to the smelting vessel.

Copper converter department means the area at a primary copper smelter in which the copper converters are located. This could include a batch copper converter or other type of copper converter, such as a continuous copper converter.

Copper matte means a material predominately composed of copper and iron sulfides produced by smelting copper ore concentrates.

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 (including any operating limit) or work practice standard;

(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 (including any operating limit) or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Emission limitation means any emission limit, opacity limit, operating limit, or visible emission limit.

Fugitive dust material means copper concentrate, dross, reverts, slag, speiss, or other solid copper-bearing materials.

Fugitive dust source means a stationary source of particulate matter emissions resulting from the handling, storage, transfer, or other management of fugitive dust materials where the source is not associated with a specific process, process vent, or stack. Examples of a fugitive dust source include, but are not limited to, on-site roadways used by trucks transporting copper concentrate, unloading of materials from trucks or railcars, outdoor material storage piles, and transfer of material to hoppers and bins.

Holding means the operating mode for a batch copper converter or a holding furnace associated with a smelting vessel during which the molten bath is maintained in the vessel but no blowing or smelting is performed nor is material added into or removed from the vessel.

New copper converter system means the copper matte is oxidized and forms copper blister by a process that is performed continuously. This system may include a flash smelting furnace, flash converting furnace, secondary gas system, a rotary dryer, anode area, matte grinding plant, hydrometallurgical plant and possibly an acid plant.

Opacity means the degree to which emissions reduce the transmission of light.

Particulate matter means any finely divided solid or liquid material, other than uncombined water, as measured by the specific reference method.

Pouring means the operating mode for a batch copper converter during which molten copper is removed from the vessel.

Primary copper smelter means any installation or any intermediate process engaged in the production of copper from copper sulfide ore concentrates through the use of pyrometallurgical techniques.

Responsible official means responsible official as defined in 40 CFR 70.2.

Roofline vents means an exhaust system designed to evacuate process fugitive emissions that collect in the roofline area of various process buildings (e.g., smelting building roof vents, converter building roof vents, etc.).

Secondary gas system means a capture system that collects the gases and fumes released when removing and transferring molten materials from one or more vessels using tapping ports, launders, and other openings in the vessels. Examples of molten material include, but are not limited to: Copper matte, slag, and blister copper.

Skimming means the batch copper converter operating mode during which molten slag is removed from the vessel.

Slag cleaning vessel means a vessel that receives molten copper-bearing material and the predominant use of the vessel is to separate this material into molten copper matte and slag layers.

Smelting vessel means a furnace, reactor, or other type of vessel in which copper ore concentrate and fluxes are smelted to form a molten mass of material containing copper matte and slag. Other copper-bearing materials may also be charged to the smelting furnace.

TEQ means the international method of expressing toxicity equivalents for dioxins/furans as defined in EPA/100/R–10/005 (incorporated by reference, see § 63.14). The Toxic Equivalency 49 Factors (TEFs) used to determine the dioxin and furan TEQs are listed in table 3 to this subpart.

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.

Table 1 to Subpart QQQ of Part 63—Applicability of General Provisions to This Subpart

As required in § 63.1457, you must comply with the requirements of the NESHAP General Provisions (subpart A of this part) shown in the following table:

Citation	Subject	Applies to this subpart	Explanation
§ 63.1	Applicability	Yes.	
§ 63.2	Definitions	Yes.	
§ 63.3	Units and Abbreviations	Yes.	
§ 63.4	Prohibited Activities	Yes.	
§ 63.5	Construction and Reconstruction	Yes.	

Citation	Subject	Applies to this subpart	Explanation
§ 63.6(a) through (d), (e)(iii), and (f)(2) and (3), (g).	Compliance with Standards and Maintenance Requirements.	Yes.	
§ 63.6(e)(1)(i)	Operation and Maintenance Requirements.	Yes before November 12, 2024. No on or after November 12, 2024.	General duty requirements to minimize emissions at all times are contained in § 63.1447(a).
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	Yes before November 12, 2024. No on or after November 12, 2024.	Malfunctions are no longer exempt.
§ 63.6(e)(2)	Reserved	No.	
§ 63.6(e)(3)	Requirement to develop a startup, shutdown, and malfunction plan.	Yes before November 12, 2024. No on or after November 12, 2024.	Startup, shutdown, and malfunction (SSM) plans are no longer necessary.
§ 63.6(f)(1)	Compliance with nonopacity emission standards during periods of startup, shutdown, and malfunction.	Yes before November 12, 2024. No on or after November 12, 2024.	Source category rules apply at all times.
§ 63.6(h)	Determining compliance with Opacity and VE standards.	No	This subpart specifies the requirements and test protocol used to determine compliance with the opacity limits.
§ 63.6(i) and (j)	Extension of Compliance and Presidential Compliance Exemption.	Yes.	
§ 63.7(a)(1) and (2)	Applicability and Performance Test Dates.	No	This subpart specifies performance test applicability and dates.
§ 63.7(a)(3), (b) through (d), (f) through (h).	Performance Testing Requirements.	Yes.	
§ 63.7(e)(1)	Performance Testing	Yes before November 12, 2024. No on or after November 12, 2024.	See §§ 63.1450 and 63.1444.
§ 63.8 except for (a)(4), (c)(1)(i) and (iii), (c)(4), (d)(3), and (f)(6).	Monitoring Requirements	Yes.	
§ 63.8(a)(4)	Additional Monitoring Requirements for Control devices in § 63.11.	No	This subpart does not require flares.
§ 63.8(c)(1)(i) and (iii)	Operation and Maintenance of and SSM plan for Continuous Monitoring Systems.	Yes before November 12, 2024. No on or after November 12, 2024.	Cross references to the general duty and SSM plan requirements in those paragraphs are no longer necessary.
§ 63.8(c)(4)	Continuous Monitoring System Requirements.	No	This subpart specifies requirements for operation of CMS.
§ 63.8(d)(3)	Quality Control Program	Yes before November 12, 2024. No on or after November 12, 2024.	See § 63.1456(a)(4)(iii).
§ 63.8(f)(6)	RATA Alternative	No	This subpart does not require continuous emission monitoring systems.
§ 63.9	Notification Requirements	Yes.	
§ 63.9(g)(5)	DATA reduction	No	This subpart specifies data reduction requirements.
§ 63.10 except for (b)(2)(i), (ii), (iv), (v), and (xiii), (c)(7), (8), and (15), and (d)(5).	Recordkeeping and reporting Requirements.	Yes.	
§ 63.10(b)(2)(i)	General Recordkeeping Requirements during Startup and Shutdown.	Yes before November 12, 2024. No on or after November 12, 2024.	No longer necessary because recordkeeping and reporting applicable to normal operations will apply to startup and shutdown.
§ 63.10(b)(2)(ii)	General Recordkeeping Requirements during Startup, Shutdown, and Malfunction and Failures to Meet Standards.	Yes before November 12, 2024. No on or after November 12, 2024.	See § 63.1456(a)(4)(iv) for recordkeeping requirements for a deviation from a standard.
§ 63.10(b)(2)(iv)	Actions Taken to Minimize Emissions during Startup, Shutdown, and Malfunction.	Yes before November 12, 2024. No on or after November 12, 2024.	See § 63.1456 for the recordkeeping requirements of actions taken to minimize emissions and record corrective actions.
§ 63.10(b)(2)(v)	Actions Taken to Minimize Emissions during Startup, Shutdown, and Malfunction.	Yes before November 12, 2024. No on or after November 12, 2024.	Requirements to document that actions taken during SSM events are consistent with SSM plan are no longer required.
§ 63.10(b)(2)(xiii)	CMS Records for RATA Alternative.	No	This subpart does not require continuous emission monitoring systems.

Citation	Subject	Applies to this subpart	Explanation
§ 63.10(c)(7)–(8)	Records of Excess Emissions and Parameter Monitoring Exceedances for CMS.	No	This subpart specifies record keeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	Yes before November 12, 2024. No on or after November 12, 2024.	This provision would be eliminated because it referenced the source's SSM plan, which is no longer required.
§ 63.10(d)(5)	SSM Reporting and Recordkeeping Requirements.	Yes before November 12, 2024. No on or after November 12, 2024.	See §§ 63.1455(c)(4) and 63.1456.
§ 63.11	Control Device Requirements	No	This subpart does not require flares.
§ 63.12	State Authority and Delegations	Yes.	
§§ 63.13 through 63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.	

Table 2 to Subpart QQQ of Part 63—Non-Mercury HAP Emission Limits

As required in § 63.1444(o), you must meet each emission limit in the following table that applies to you.

For. . .	You must meet the following emission limit
Each new and existing combination of stacks or other vents from the copper concentrate dryers, converting department, the anode refining department, and the smelting vessels.	Benzene emissions must not exceed 1.7E–03 lb/ton copper concentrate feed charged to the smelting vessel.
Each new and existing combination of stacks or other vents from the copper concentrate dryers, converting department, the anode refining department, and the smelting vessels.	Toluene emissions must not exceed 8.4E–04 lb/ton copper concentrate feed charged to the smelting vessel.
Each new and existing combination of stacks or other vents from the copper concentrate dryers, converting department, the anode refining department, and the smelting vessels.	Chlorine emissions must not exceed 5.4E–03 lb/ton copper concentrate feed charged to the smelting vessel.
Each new and existing combination of stacks or other vents from the copper concentrate dryers, converting department, the anode refining department, and the smelting vessels.	Hydrogen chloride emissions must not exceed 1.5E–03 lb/ton copper concentrate feed charged to the smelting vessel.
Each new and existing combination of stacks or other vents from the copper concentrate dryers, converting department, the anode refining department, and the smelting vessels.	Polycyclic aromatic hydrocarbons (excluding naphthalene) emissions must not exceed 1.0E–04 lb/ton copper concentrate feed charged to the smelting vessel.
Each new and existing combination of stacks or other vents from the copper concentrate dryers, converting department, the anode refining department, and the smelting vessels.	Naphthalene emissions must not exceed 2.8E–04 lb/ton copper concentrate feed charged to the smelting vessel.
Each new and existing combination of stacks or other vents from the copper concentrate dryers, converting department, the anode refining department, and the smelting vessels.	Dioxins/Furans emissions [1] must not exceed 6.0E+01 ng TEQ/Mg copper concentrate feed charged to the smelting vessel.

[1] Determined using the toxic equivalency factors listed in Table 2 of Recommended Toxicity Equivalence Factors (TEFs) for Human Health Risk Assessments of 2, 3, 7, 8- Tetrachlorodibenzo-p-dioxin and Dioxin-Like Compounds (incorporated by reference, see § 63.14).

TABLE 3 TO SUBPART QQQ OF PART 63—2010 TOXIC EQUIVALENCY FACTORS (TEFS)

Congener	TEF (mammals)
2,3,7,8-Te CDD	1
1,2,3,7,8-Pe CDD	1
1,2,3,4,7,8-HxCDD	0.1
1,2,3,6,7,8-HxCDD	0.1
1,2,3,7,8,9-HxCDD	0.1
1,2,3,4,6,7,8-HpCDD	0.01
OCDD	0.0003
2,3,7,8-Te CDF	0.1
1,2,3,7,8-Pe CDF	0.03
2,3,4,7,8-Pe CDF	0.3
1,2,3,4,7,8-HxCDF	0.1
1,2,3,6,7,8-HxCDF	0.1
2,3,4,6,7,8-HxCDF	0.1
1,2,3,7,8,9-HxCDF	0.1
1,2,3,4,6,7,8-HpCDF	0.01
1,2,3,4,7,8,9-HpCDF	0.01
OCDF	0.0003

TABLE 4 TO SUBPART QQQ OF PART 63—COMPLIANCE DATES FOR AMENDMENTS BEING PROMULGATED ON MAY 13, 2024

If the construction/reconstruction date is . . .	Then the owner or operator must comply with . . .	And the owner or operator must achieve compliance . . .
On or before January 11, 2022.	Requirements for existing sources in §§ 63.1444(f)(2) and (3), (l); 63.1446; 63.1449;[1] 63.1450(a) and (d); and 63.1451 through 63.1456, as applicable.	On or before May 13, 2025.
	Requirements for existing sources in §§ 63.1444(h); 63.1449;[1] 63.1450(e); and 63.1451 through 63.1456, as applicable.	On or before May 13, 2026.
After January 11, 2022	Requirements for new sources in §§ 63.1444(e)(1) and (2), (f)(2) and (3), (h), (m); 63.1446; 63.1449;[1] 63.1450(a), (d), (e); and 63.1451 through 63.1456, as applicable.	Upon initial startup or May 13, 2024, whichever is later.
On or before July 24, 2023.	Requirements for existing sources in §§ 63.1444(g); 63.1449;[1] 63.1450(a); and 63.1451 through 63.1456, as applicable.	On or before May 13, 2027.
	Requirements for existing sources in §§ 63.1444(o); 63.1449;[1] 63.1450(f); and 63.1451 through 63.1456, as applicable.	On or before May 13, 2025.
	Requirements for existing sources in §§ 63.1444(q); 63.1449;[1] 63.1450(a), (g); and 63.1451 through 63.1456, as applicable.	On or before November 12, 2024.
After July 24, 2023	Requirements for new sources in §§ 63.1444(o), (q); 63.1449;[1] 63.1450(a), (f), (g); and 63.1451 through 63.1456, as applicable.	Upon initial startup or May 13, 2024, whichever is later.
On or before May 13, 2024.	Requirements for existing sources in §§ 63.1444(p); 63.1449;[1] 63.1450(g); and 63.1451 through 63.1456, as applicable.	On or before May 13, 2027.

[1] Section 63.1449(a) provides that any necessary performance test is conducted within 180 days of the compliance date.

FIGURE 1 TO SUBPART QQQ OF PART 63—DATA SUMMARY SHEET FOR DETERMINATION OF AVERAGE OPACITY

Clock time	Number of converters blowing	Converter aisle activity	Average opacity for 1-minute interval (percent)	Visible emissions interference observed during 1-minute interval? (yes or no)	Average opacity for 1-minute interval blowing without visible emission interferences (percent)

Subpart EEEEEE—National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelting Area Sources

■ 5. Amend § 63.11147 by revising paragraphs (b)(6), (c)(1) and (5), (d), and (e) to read as follows:

§ 63.11147 What are the standards and compliance requirements for existing sources not using batch copper converters?

* * * * *

(b) * * *

(6) You must submit to the permitting authority by the 20th day of each month a report summarizing the 24-hour average mass PM_{10} emissions rates for the previous month. Beginning November 12, 2024, the owner or operator must electronically submit all subsequent reports in PDF format to the EPA via CEDRI, which can be accessed through EPA's CDX (*https://cdx.epa.gov/*) following the procedures specified in § 63.9(k).

* * * * *

(c) * * *

(1) At all times, you must maintain and operate 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 or 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 permitting authority 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.

* * * * *

(5) Before November 12, 2024, as an alternative to the requirements in paragraph (c)(4) of this section, you must comply with the startup, shutdown, and malfunction requirements in § 63.6(e)(3). On or after November 12, 2024, you may not use the requirements in § 63.6(e)(3) as an alternative to the requirements in paragraph (c)(4) of this section. You must comply with all emissions limitation or work practice standards in this subpart at all times.

(d) *Deviations.* You must submit written notification to the permitting authority of any deviation from the requirements of this subpart, including the number, date, time, duration, and the cause of such events (including unknown cause, if applicable); a list of the affected sources or equipment; an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions; and the probable cause of such deviations and any corrective actions or preventative measures taken. You must submit this notification within 14 days of the date the deviation started.

(e) *Reports.* (1) You must submit semiannual monitoring reports to your permitting authority. All instances of deviations from the requirements of this subpart must be clearly identified in the reports. The report must contain the number, date, time, duration, and the cause of each deviation (including unknown cause, if applicable); a list of the affected sources or equipment; an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions; and the probable cause of such deviations and any corrective actions or preventative measures taken. Examples of methods used to estimate the emissions would include product-loss calculations, mass balance calculations, measurements when available, or engineering judgment based on known process parameters.

(2) Beginning November 13, 2024, the owner or operator must electronically submit all subsequent semiannual monitoring reports in PDF format to the EPA via CEDRI, which can be accessed through EPA's CDX (*https://cdx.epa.gov/*) following the procedures specified in § 63.9(k).

* * * * *

■ 6. Amend § 63.11148 by:

■ a. Revising paragraphs (a)(1), (a)(3)(ii), (a)(4)(iv), (b)(1), (b)(2)(i), (b)(4), (c)(2) and (4), (e)(3), (f)(1), (f)(4)(ii) and (iii), (f)(5), (g), and (h); and

■ b. Adding paragraph (i).

The revisions and addition read as follows:

§ 63.11148 What are the standards and compliance requirements for existing sources using batch copper converters?

(a) * * *

(1) For each copper concentrate dryer, you must not discharge to the atmosphere from the dryer vent any gases that contain filterable particulate matter (PM) in excess of 0.022 grains per dry standard cubic foot (gr/dscf).

* * * * *

(3) * * *

(ii) You must not cause to be discharged to the atmosphere from the capture system used to comply with paragraph (a)(3)(i) of this section any gases that contain filterable PM in excess of 0.022 gr/dscf.

(4) * * *

(iv) For each secondary capture system that is used to comply with paragraph (a)(4)(ii) of this section and is not vented to a gas cleaning system controlling PM and a sulfuric acid plant, you must not cause to be discharged to the atmosphere any gases that contain filterable particulate matter in excess of 0.02 grains/dscf.

(b) * * *

(1) Each COMS must meet Performance Specification 1 in appendix B to 40 CFR part 60.

(2) * * *

(i) You must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in appendix B to 40 CFR part 60.

* * * * *

(4) You must log in ink or electronic format and maintain a record of 24-hour opacity measurements performed in accordance with paragraph (b)(3) of this section and any corrective actions taken, if any. A record of corrective actions taken must include the start date, start time, and duration in hours during which the 24-hour rolling average opacity exceeded 15 percent and the start date, start time and type of the corrective action and the date and time the corrective action was completed.

(c) * * *

(2) The baghouse leak detection system must meet the specifications and requirements in paragraphs (c)(2)(i) through (vi) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations that can effectively discern any dysfunctional leaks of the baghouse.

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

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

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

(v) The bag leak detection system must be installed downstream of the baghouse.

(vi) The bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations. The calibration of the system must, at a minimum, consist of establishing the relative baseline output level by adjusting the sensitivity and the averaging period of the device and establishing the alarm set points and the alarm delay time.

* * * * *

(4) You must log in ink or electronic format and maintain a record of installation, calibration, maintenance, and operation of the bag leak detection system. If the bag leak detection system alarm sounds, the records must include an identification of the date and time of all bag leak detection alarms, their cause, the time you initiated corrective actions, and an explanation of the corrective actions taken, including the date corrective actions were completed, if any.

* * * * *

(e) * * *

(3) Before November 12, 2024, you must conduct each performance test according to § 63.7(e)(1) using the test methods and procedures in paragraphs (e)(3)(i) through (v) of this section. On or after November 12, 2024, you must conduct each performance test using the test methods and procedures in paragraphs (e)(3)(i) through (vi) of this section.

(i) Method 1 or 1A in appendix A–1 to 40 CFR part 60 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.

(ii) Method 2, 2A, 2C, 2D, 2F, or 2G in appendices A–1 and A–2 to 40 CFR part 60 to determine the volumetric flow rate of the stack gas.

(iii) Method 3, 3A, or 3B in appendix A–2 to 40 CFR part 60 to determine the dry molecular weight of the stack gas. You may use ANSI/ASME PTC 19.10–1981 (incorporated by reference—see § 63.14) as an alternative to EPA Method 3B manual portion only and not the instrumental portion.

(iv) Method 4 in appendix A–3 to 40 CFR part 60 to determine the moisture content of the stack gas.

(v) Method 5 in appendix A–3 to 40 CFR part 60 to determine the PM concentration for negative pressure baghouses or Method 5D in appendix A–3 to 40 CFR part 60 for positive pressure baghouses. A minimum of three valid test runs are needed to comprise a PM performance test.

(vi) You must conduct each performance test that applies to your affected source under normal operating conditions of the affected source. The owner or 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 such conditions represent the entire range of normal operation, including operational conditions for maximum emissions if such emissions are not expected during maximum production. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(f) * * *

(1) At all times, you must maintain and operate 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 or 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 permitting authority 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.

* * * * *

(4) * * *

(ii) You must document through signed contemporaneous logs or other relevant evidence that an emergency occurred, and you can identify the probable cause, your facility was being operated properly at the time the emergency occurred, and the corrective actions taken to minimize emissions as required by paragraph (f)(4)(i) of this section. Documentation must include the date, time, duration, of such events (including unknown cause, if applicable); a list of the affected sources or equipment; and an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions.

(iii) You must submit a notice of the emergency to the permitting authority within two working days of the time when emission limitations were exceeded due to the emergency (or an alternate timeframe acceptable to the permitting authority). This notice must contain the number, date, time, duration, and the cause of such events (including unknown cause, if applicable); a list of the affected sources or equipment; an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions; and the probable cause of such deviations and any corrective actions or preventative measures taken.

(5) Before November 12, 2024, as an alternative to the requirements in paragraph (f)(4) of this section, you must comply with the startup, shutdown, and malfunction requirements in § 63.6(e)(3). On or after November 12, 2024, you may not use the requirements in § 63.6(e)(3) as an alternative to the requirements in paragraph (f)(4) of this section. Emissions limitation or work practice standards in this subpart apply at all times.

(g) *Recordkeeping requirements.* (1) You must maintain records of the occurrence and duration in hours of each startup, shutdown, or malfunction of process, air pollution control, and monitoring equipment.

(2) 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, cause and duration of each failure.

(3) For each failure to meet an applicable standard, record and retain a list of the affected sources or equipment, whether the failure occurred during a period of startup, shutdown or malfunction, actions taken to minimize emissions, an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions.

(4) Record actions taken to minimize emissions in accordance with § 63.11147(c), paragraph (f) of this section, or § 63.11149(c)(3) as applicable, and any corrective actions taken to return the affected unit to its normal or usual manner of operation.

(5) You must maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this section recorded in a permanent form suitable for inspection. The file must be retained for at least 5 years following the date of such measurements, maintenance, and reports.

(6) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

(h) *Reporting requirements.* (1) You must prepare and submit to the permitting authority an excess emissions and monitoring systems performance report and summary report every calendar quarter. A less frequent reporting interval may be used for either report as approved by the permitting authority.

(2) The summary report must include the information in paragraphs (h)(2)(i) through (iv) of this section.

(i) The magnitude of excess emissions computed, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period. Examples of methods used to estimate the emissions would include product-loss calculations, mass balance calculations, measurements when available, or engineering judgment based on known process parameters.

(ii) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(iii) The date, time, and duration in hours identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(iv) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information must be stated in the report.

(i) *Electronic reporting requirements.* Beginning on November 13, 2024, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test following the procedures specified in § 63.9(k).

(1) *Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.* Submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(2) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

■ 7. Revise § 63.11149 to read as follows:

§ 63.11149 What are the standards and compliance requirements for new sources?

(a) *Emissions limits and work practice standards.* (1) You must not discharge to the atmosphere exhaust gases that contain filterable PM in excess of 0.6 pound per ton of copper concentrate feed charged on a 24-hour average basis from any combination of stacks, vents, or other openings on furnaces, reactors, or other types of process vessels used for the production of anode copper from copper sulfide ore concentrates by pyrometallurgical techniques. Examples of such process equipment include, but are not limited to, copper concentrate dryers, smelting flash furnaces, smelting bath furnaces, converting vessels, combined smelting and converting reactors, anode refining furnaces, and anode shaft furnaces.

(2) You must operate a capture system that collects the gases and fumes released during the transfer of molten materials from smelting vessels and converting vessels and conveys the collected gas stream to a baghouse or other PM control device.

(3) You must operate one or more capture systems that collect the gases and fumes released from each vessel used to refine blister copper, remelt anode copper, or remelt anode scrap and convey each collected gas stream to a baghouse or other PM control device. One control device may be used for multiple collected gas streams.

(b) *Monitoring requirements.* (1) You must install, operate, and maintain a PM continuous emissions monitoring system (CEMS) to measure and record PM concentrations and gas stream flow rates for the exhaust gases discharged to the atmosphere from each affected source subject to the emissions limit in paragraph (a)(1) of this section. A single PM CEMS may be used for the combined exhaust gas streams from multiple affected sources at a point before the gases are discharged to the atmosphere. For each PM CEMS used to comply with this paragraph (b)(1), you must meet the requirements in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must install, certify, operate, and maintain the PM CEMS according to EPA Performance Specification 11 in appendix B to 40 CFR part 60, and the quality assurance requirements of Procedure 2 in appendix F to 40 CFR part 60.

(ii) You must conduct an initial performance evaluation of the PM CEMS according to the requirements of Performance Specification 11 in appendix B to 40 CFR part 60. Thereafter, you must perform the performance evaluations as required by Procedure 2 in appendix F to 40 CFR part 60.

(iii) You must perform quarterly accuracy determinations and daily calibration drift tests for the PM CEMS according to Procedure 2 in appendix F to 40 CFR part 60.

(2) You must install, operate, and maintain a weight measurement system to measure and record the weight of the copper concentrate feed charged to the smelting vessel on a daily basis.

(3)(i) You must comply with the requirements in § 63.8(d)(1) and (2).

(ii) The owner or operator shall keep the written procedures required in § 63.8(d)(1) and (2) on record 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, the owner or operator shall 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).

(c) *Compliance requirements.* (1) You must demonstrate initial compliance with the emissions limit in paragraph (a)(1) of this section using the procedures in paragraph (c)(2) this section within 180 days after startup and report the results in your notification of compliance status no later than 30 days after the end of the compliance demonstration.

(2) You must demonstrate continuous compliance with the emissions limit in paragraph (a)(1) of this section using the procedures in paragraphs (c)(2)(i) through (iii) of this section whenever your facility is producing copper from copper concentrate.

(i) You must continuously monitor and record PM emissions, determine and record the daily (24-hour) value for each day, and calculate and record the daily average pounds of filterable PM per ton of copper concentrate feed charged to the smelting vessel according to the requirements in paragraph (b) of this section.

(ii) You must calculate the daily average at the end of each calendar day for the preceding 24-hour period.

(iii) You must maintain records of the calculations of daily averages with supporting information and data, including measurements of the weight of copper concentrate feed charged to the smelting vessel. Collected PM CEMS data must be made available for inspection.

(3)(i) At all times, you must maintain and operate 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 or 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 permitting authority 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.

(ii) All pollution control equipment must be installed, maintained, and operated properly. Instructions from the vendor or established maintenance practices that maximize pollution control must be followed. All necessary equipment control and operating devices, such as pressure gauges, amp meters, volt meters, flow rate indicators, temperature gauges, continuous emissions monitor, etc., must be installed, operated properly and easily accessible to compliance inspectors. A copy of all manufacturers' operating instructions for pollution control equipment and pollution emitting equipment must be maintained at your facility site. These instructions must be available to all employees who operate the equipment and must be made available to the permitting authority upon request. Maintenance records must be made available to the permitting authority upon request.

(iii) You must document the activities performed to assure proper operation and maintenance of the air pollution control equipment and monitoring systems or devices. Records of these activities must be maintained as required by the permitting authority.

(4)(i) 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, the cause and duration of each failure.

(ii) For each failure to meet an applicable standard, record and retain a list of the affected sources or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions.

(iii) Record actions taken in accordance with the general duty requirements to minimize emissions in paragraph (c)(3) of this section and any corrective actions taken to return the affected unit to its normal or usual manner of operation.

(d) *Alternative startup, shutdown, and malfunction requirements.* Before November 12, 2024, you must comply with the requirements specified in this paragraph (d) as an alternative to the requirements in § 63.6(e)(3). On or after November 12, 2024, you may not use the requirements in § 63.6(e)(3) as an alternative to the requirements in this paragraph (d). Emissions limitation or work practice standards in this subpart apply at all times. In the event of an emergency situation, you must comply with the requirements specified in paragraphs (d)(1) through (3) of this section. For the purpose of complying with this paragraph (d), an emergency situation is any situation arising from sudden and reasonably unforeseeable events beyond the control of the facility owner or operator that requires immediate corrective action to restore normal operation, and that causes the affected source to exceed an applicable emissions limitation under this subpart, due to unavoidable increases in emissions attributable to the emergency. An emergency must not include noncompliance to the extent it is caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

(1) During the period of the emergency, you must implement all reasonable steps to minimize levels of emissions that exceeded the emission standards or other applicable requirements in this subpart.

(2) You must document through signed contemporaneous logs or other relevant evidence that an emergency occurred and you can identify the probable cause, your facility was being operated properly at the time the emergency occurred, and the corrective actions taken to minimize emissions as required by paragraph (d)(1) of this section.

(3) You must submit a notice of the emergency to the permitting authority within two working days of the time when emissions limitations were exceeded due to the emergency (or an alternate timeframe acceptable to the permitting authority). This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

(e) *Reports.* (1) You must submit to the permitting authority by the 20th day of each month a summary of the daily average PM per ton of copper concentrate feed charged to the smelting vessel for the previous month.

(2) Beginning November 12, 2024, the owner or operator must electronically submit all subsequent monthly PM emission reports and notification of compliance status in PDF format to the EPA via CEDRI, which can be accessed through EPA's CDX (*https://cdx.epa.gov/*) following the procedures specified in § 63.9(k).

(3) For each deviation from an emission limitation in paragraph (a)(1) of this section occurring at an affected source, you must include in your semiannual monitoring report the information in paragraphs (e)(3)(i) through (x) of this section.

(i) The date and time that each malfunction started and stopped.

(ii) The start date, and start time, and duration in hours (or minutes for CEMS) that each continuous monitoring system was inoperative, except for zero (low-level) and high-level checks.

(iii) The start date, start time, and duration in hours (or minutes for CEMS) that each continuous monitoring system was out-of-control, including the information in § 63.8(c)(8).

(iv) The total duration in hours (or minutes for CEMS) of all deviations for each CMS during the reporting period, the total operating time in hours of the affected source during the reporting period, 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.

(v) A breakdown of the total duration in hours (or minutes for CEMS) of the deviations during the reporting period including those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(vi) The total duration in hours (or minutes for CEMS) of continuous monitoring system downtime for each CMS during the reporting period, the total operating time in hours of the affected source during the reporting period, and the total duration of CMS downtime as a percent of the total source operating time during the reporting period.

(vii) A brief description of the process units.

(viii) The monitoring equipment manufacturer and model number and the pollutant or parameter monitored.

(ix) The date of the latest continuous monitoring system certification or audit.

(x) A description of any changes in continuous monitoring systems, processes, or controls since the last reporting period.

■ 8. Amend § 63.11151 by adding the definition ''Blowing'' in alphabetical order and revising the definition ''Capture system'' to read as follows:

§ 63.11151 What definitions apply to this subpart?

* * * * *

Blowing means the operating mode for a batch copper converter during which air or oxygen-enriched air is injected into the molten converter bath.

Capture system means the collection of components used to capture gases and fumes released from one or more emissions points and then convey the captured gas stream to a control device. A capture system may include, but is not limited to, the following components as applicable to a given capture system design: duct intake devices, hoods, enclosures, ductwork, dampers, manifolds, plenums, and fans.

* * * * *

■ 9. Amend § 63.11152 by:

■ a. Revising paragraph (c) introductory text;

■ b. Removing the undesignated paragraph after paragraph (c)(5); and

■ c. Adding paragraph (c)(6).

The revision and addition read as follows:

§ 63.11152 Who implements and enforces this subpart?

* * * * *

(c) The authorities that will not be delegated to State, local, or tribal agencies are listed in paragraphs (c)(1) through (6) of this section.

* * * * *

(6) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

■ 10. Revise table 1 to subpart EEEEEE of part 63 to read as follows:

Table 1 to Subpart EEEEEE of Part 63—Applicability of General Provisions to This Subpart

As required in § 63.11150(a), you must comply with the requirements of the NESHAP General Provisions (subpart A of this part) as shown in the following table.

Citation	Subject	Applies to this subpart?	Explanation
§ 63.1(a)(1) through (4), (6), and (10) through (12), (b)(1) and (3), (c)(1), (2), and (5), (e).	Applicability	Yes..	
§ 63.1(a)(5) and (7) through (9), (b)(2), (c)(3) and (4), (d).	Reserved	No..	
§ 63.2	Definitions	Yes..	
§ 63.3	Units and Abbreviations	Yes..	
§ 63.4	Prohibited Activities and Circumvention.	Yes..	
§ 63.5	Preconstruction Review and Notification Requirements.	No..	
§ 63.6(a), (b)(1) through (5) and (7), (c)(1), (2), and (5).	Compliance with Standards and Maintenance Requirements—Applicability and Compliance Dates.	Yes..	
§ 63.6(e)(1)(i)	Operation and Maintenance Requirements—general duty to minimize emissions.	Yes before November 12, 2024 No on or after November 12, 2024.	See §§ 63.11147(c) and 63.11148(f) for the general duty to minimize emissions at all times at existing sources. See § 63.11149(c)(3) for the general duty to minimize emissions at all times at new sources.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable..	Yes before November 12, 2024 No on or after November 12, 2024.	Malfunctions are no longer exempt.
§ 63.6(e)(1)(iii)		Yes..	
§ 63.6(e)(3)	Startup, Shutdown, and Manufacturing Plan.	Yes before November 12, 2024 No on or after November 12, 2024.	The requirements for emergency situations for existing sources are contained in §§ 63.11147(c)(5) and 63.11148(f)(5). See § 63.11149(d) for the emergency requirements for new sources.
§ 63.6(f)(1)	Compliance with Nonopacity Emission Standards.	Yes before November 12, 2024 No on or after November 12, 2024.	Emission standards apply at all times. Some requirements of § 63.6(f)(1) are no longer applicable.
§ 63.6(f)(2) through (3)		Yes..	
§ 63.6(g), (i), (j)	Compliance with Nonopacity Emission Standards.	Yes..	
§ 63.6(h)(1)	Compliance with Opacity and Visible Emission Standards.	Yes before November 12, 2024 No on or after November 12, 2024.	Requirements apply to new sources but not existing sources. Emission standards apply at all times. Some requirements of § 63.6(h)(1) are no longer applicable.
§ 63.6(b)(6), (c)(3) and (4), (d), (e)(2), (e)(3)(ii), (h)(2)(ii), (h)(3), (h)(5)(iv), (i)(15).	Reserved	No..	

Citation	Subject	Applies to this subpart?	Explanation
§ 63.6(h)(2) through (4), (h)(5)(i) through (iii), (h)(6) through (9).		Yes/No.	Requirements apply to new sources but not existing sources.
§ 63.7(a), (e)(2) through (4), (f), (g), (h).	Performance Testing Requirements.	Yes..	
§ 63.7(e)(1)	Performance Testing Requirements.	No	See § 63.11148(e) for performance testing requirements.
§ 63.7(b), (c)		Yes/No	Notification of performance tests and quality assurance program apply to new sources but not existing sources.
§ 63.8(a)(1) and (2), (b), (c)(1)(ii), (c)(2) through (8), (f), (g).	Monitoring Requirements	Yes..	
§ 63.8(c)(1)(i) and (iii)	General Duty and SSM Plan Requirements for Continuous Monitoring Systems.	Yes before November 12, 2024. No on or after November 12, 2024..	
§ 63.8(a)(3)	Reserved	No..	
§ 63.8(a)(4)		No	This subpart does not require flares.
§ 63.8(d)(1) and (2), (e)	Quality Control	Yes/No	Requirements for quality control program and performance evaluations apply to new sources but not existing sources.
§ 63.8(d)(3)	Written Procedures for Continuous Monitoring Systems.	Yes before November 12, 2024 No on or after November 12, 2024.	Requirements for quality control program and performance evaluations apply to new sources but not existing sources. See § 63.11149(b)(3).
§ 63.9(a), (b)(1), (2), and (5), (c), (d), (h)(1) through (3), (5), and (6), (i), (j).	Notification Requirements	Yes..	
§ 63.9(b)(3), (h)(4)	Reserved	No..	
§ 63.9(b)(4), (f)		No..	
§ 63.9(e), (g)		Yes/No	Notification requirements for performance test and use of continuous monitoring systems apply to new sources but not existing sources.
§ 63.9(k)	Electronic submission of notifications or reports.	Yes..	
§ 63.10(a), (b)(1), (d)(1), (2), and (4), (f).	Recordkeeping and Reporting Requirements.	Yes/No	Recordkeeping requirements apply to new sources but not existing sources.
§ 63.10(b)(2)(iii) and (vi) through (xiv), (b)(3), (c)(1), (5) through (8), and (10) through (14), (e)(1) and (2).		Yes/No	Recordkeeping requirements apply to new sources but not existing sources.
§ 63.10(b)(2)(i) through (ii) and (iv) through (v).	General Recordkeeping Requirements and Actions to Minimize Emissions During Startup, Shutdown, and Malfunction.	Yes before November 12, 2024 No on or after November 12, 2024.	Recordkeeping requirements apply to new sources but not existing sources. See § 63.11149(c)(4). Startup, Shutdown, and Malfunction are no longer exempt from emission standards. See § 63.11148(g).
§ 63.10(c)(2) and (4) and (9)	Reserved	No..	
§ 63.10(c)(15)	Use of Startup, Shutdown, and Malfunction Plan.	For new sources, Yes before November 12, 2024. No on or after November 12, 2024.	Recordkeeping requirements apply to new sources but not existing sources. Startup, Shutdown, and Malfunction Plans are no longer required.
§ 63.10(d)(3), (e)(4)		No	Reporting requirements apply to new sources but not existing sources.
§ 63.10(d)(5)	Startup, Shutdown, and Malfunction Reporting.	For new sources, Yes before November 12, 2024. No on or after November 12, 2024.	Reporting requirements apply to new sources but not existing sources. See §§ 63.11147(e), 63.11148(h), 63.11149(e)(2).
§ 63.10(e)(3)		Yes/No	Reporting requirements apply to new sources but not existing sources.
§ 63.11	Control Device Requirements	No	This subpart does not require flares.

Citation	Subject	Applies to this subpart?	Explanation
§ 63.12	State Authorities and Delegations	Yes..	
§ 63.13	Addresses	Yes..	
§ 63.14	Incorporations by Reference	Yes..	
§ 63.15	Availability of Information and Confidentiality.	Yes..	
§ 63.16	Performance Track Provisions	Yes..	

[FR Doc. 2024–09883 Filed 5–10–24; 8:45 am]

BILLING CODE 6560–50–P